Santa Clara Valley Water District

FC 1025 (08/17/11)

Meeting Date:	03/26/13
Agenda Item:	4.2
Unclassified Manager:	F. Maitski
Extension:	2284
Director(s):	All

BOARD AGENDA MEMO

SUBJECT: Energy Optimization Plan Development Update

RECOMMENDATION:

A. Receive technical reports related to energy conservation, energy efficiency, and renewable energy that support development of the District's Energy Optimization Plan; and

B. Receive and discuss staff's recommendations for activities to include in the District's Energy Optimization Plan.

SUMMARY:

This presents opportunities for energy optimization and recommendations for inclusion in the District's Energy Optimization Plan. The Energy Optimization Plan, to be completed in September 2013, will present the District's strategies and plans to conserve energy, improve energy efficiency, and develop additional renewable energy supplies. Staff provided the Board with an update on energy optimization on November 27, 2012. At that time, staff reported that a consultant was preparing technical reports on key areas related to energy optimization and that staff would return to the Board with recommendations in March 2013. This memo transmits and summarizes the consultant's reports, including opportunities for energy optimization. In addition, presented are recommendations on which opportunities should be included in the Energy Optimization Plan. Specifically, information is presented on:

1. Energy Audit results and recommendations,
2. In-conduit hydroelectric generation opportunities and recommendations,
3. Photo Voltaic (PV) solar power opportunities and recommendations,
4. Liquid fuels alternatives and recommendations,
5. Anderson Hydroelectric optimization and recommendations, and
6. Next steps.

The District's energy management and optimization activities support the following Board policies:

- E-1.3. A net positive impact on the environment is important in support of the District mission and is reflected in what we do,
- E-4.3. Strive for zero net greenhouse gas emission or carbon neutrality, and
- EL-4.2. Spend in ways that are cost-efficient.

1. Energy Audit of Facilities

The consultant, Black & Veatch, conducted an energy audit of key load centers that the District operates (Attachment 1). The audit included a site visit and energy analysis of the major power consuming facilities, including the three large pumping stations (Pacheco, Coyote, and Vasona), three water treatment plants (Rinconada, Santa Teresa, and Penitencia), and both the Headquarters and Administration buildings. Offsite energy analyses were also conducted for the remaining buildings. The purpose of the work was to understand where significant energy is used within the District and the opportunities for improvements.

The energy audit includes the following findings:

- District energy consumption is distributed at the Pumping Plants (70 percent), Water Treatment Plants (21 percent), and the Non-Process Buildings (9 percent).
- Pacheco Pumping Plant has the highest energy intensity (energy in kilowatt-hour used to pump one million gallons of water, represented as kWh/MG)) and the highest energy use. For purposes of overall energy consumption measures, it is worthwhile to investigate this facility for energy efficiency improvements.
- Rinconada Water Treatment Plant has the highest energy use intensity (energy in kilowatt-hour used to treat one million gallons of water) and highest energy use of the three treatment plants and produces approximately 46 percent of the total treated water produced by the District. The consultant recommended evaluating Rinconada for energy efficiency improvements.
- Penitencia Water Treatment Plant has higher energy use intensity than Santa Teresa, even though it uses the same treatment processes. Therefore, the consultant recommends future investigation for energy and cost reduction measures.
- There are opportunities for energy efficiency improvements at the Almaden campus, particularly at the Headquarters Building. Based on historic energy use, the consultant estimated the District could reduce energy use by 15 percent, with an annual savings potential of $79,000. The consultant recommends further investigation of facility management for energy efficiency improvements.

The audit identified 55 specific recommendations for potential energy savings and rated them on the amount of energy saved compared to the cost of implementation. The recommendations include: additional pumping efficiency at the large pump stations (especially Pacheco Pumping Plant) and treatment plants; investigating filter media backwashing operations to increase energy efficiency at all treatment plants; optimizing heating, ventilating and air conditioning (HVAC) controls at all buildings; investigating HVAC system replacements; replacing older motors with higher efficiency models where appropriate; and replacing outdoor lights at the Headquarters Building with equivalent compact fluorescent technologies.

The consultant did not provide an estimate of the overall energy savings that could be achieved by implementing the individual recommendations. Instead, the recommendations were rated high, medium, and low in terms of cost and energy savings. Staff is evaluating the recommendations and will work with consultant to develop detailed estimates of energy savings and costs associated with the recommendations. A preliminary analysis of implementing the consultants recommendations at Pacheco Pumping Plan, Rinconada Water Treatment Plant, and the Almaden Campus are presented in Attachment 1A. The detailed estimates of energy savings and costs are scheduled for completion in June 2013. The estimates will feed into the Energy Optimization Plan.

Implementation of Energy Audit Recommendations

Staff recommends completing detailed cost and energy savings estimates and then including the activities that are economically feasible[1] in the Energy Optimization Plan. Most of activities are operations activities, but some, such as HVAC system replacements, could be capital projects. It should be noted that staff has already been making ongoing improvements (e.g., using higher efficiency lamps and motors) as assets are rehabilitated or replaced. The energy savings associated with these past improvements will also be presented in the Energy Optimization Plan.

2. In-Conduit Hydroelectric Generation

The consultant evaluated 41 sites throughout the District's water transmission and distribution system where pressure reduction is necessary and identified 13 sites with potential for hydroelectric generation based on their historic pressure and flow conditions, construction, and regulatory requirements. The consultant's report is provided in Attachment 2.

The 13 sites were then evaluated for their economic feasibility. Nine of the thirteen sites were determined to be economically feasible (six sites without financial incentives and three sites with some type of green incentive to be economically viable). The benefit to cost ratio for nine feasible sites ranges from 1.01 to 2.39.

Some of the issues with installing in-conduit hydroelectric generation facilities are:

- Pressure needs and wants of downstream water retailers,
- Noise associated with the turbines and water cooling systems in residential neighborhoods,
- Constraints with installation when buried facilities are necessary,
- Potential conflicts with other utilities at the site,
- Construction impacts such as traffic and noise, and
- Downstream retailer in-conduit hydroelectric facilities.

If all the nine sites were retrofitted for in-conduit hydro-electric generation, they could produce a combined total of about 11,000 MWh of electrical power annually, or about 8% of the District's total Calendar Year (CY) 2011 electrical usage. The capital costs per facility would range from about $700,000 to $1,600,000. Annual operations and maintenance costs per facility would range from about $40,000 to $70,000.

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[1] Economically feasible means the net present value of the benefits over the lifetime of the project exceed the net present value of the costs over the lifetime of the project.

Implementation of In-Conduit Hydroelectric Generation Recommendations

Staff proposes including development of cost-effective in-conduit hydroelectric generation opportunities in the Energy Optimization Plan. This will require working with retailers on changes in pressure at the turnouts; entering into agreements with PG&E; and completing site-specific project validation, planning, and design. Implementation scheduling will depend on investment and other priorities.

3. Photo Voltaic (PV) Solar Power

The solar power generation feasibility study (Attachment 3) reviewed three vacant District-owned properties (one in the east side hills in San Jose, one in Coyote Valley, and one near Morgan Hill) and vacant areas at two water treatment plants (Santa Teresa and Penitencia) for their potential of producing solar power. Solar power feasibility at Rinconada Water Treatment Plant is being conducted through its Reliability Improvement Project. The five sites that were reviewed have the potential for producing approximately 21,000 MWh of energy per year, or about 15 percent of the District's CY 2011 usage. The bulk of the energy production (19,000 MWh per year) would occur at the three vacant properties. It should be noted that two of the vacant parcels are adjacent to residential communities.

The study also evaluated the risks and costs of four methods for project implementation – conventional District build and own, a power purchase agreement (PPA) with a third party, pre-pay PPA, and sale and leaseback. Each of these methods is summarized below.

Build and Own: The District would take on the financial, project development, and project operation risks with this option. The District would not be able to take advantage of any tax incentive programs. The District would build, own, and operate the solar project. This is the highest cost method of project implementation with the cost of energy ranging from $121 to $144 per MWh.

Power Purchase Agreement (PPA): The District would purchase power from a third-party that would build, own, and operate the project. This is the most common way in which renewable energy projects are developed and provides a low-risk delivery of power to the purchaser. The purchaser pays for the power, usually for a set cost per unit of energy, as it uses the power. This is the middle cost method of project implementation with the cost of energy ranging from $105 to $129 per MWh mainly because the developer would be able to take advantage of a federal investment tax credit (ITC).

Pre-Pay Power Purchase Agreement: This is similar to the PPA, except that payment for all or part of the power is made in one lump sum at the beginning of the agreement term. Pre-paying for electricity can be viewed as a relatively high risk financially because the District would have to pay an amount that is very close to the construction cost of the project upfront and would be accepting the role that is traditional filled by project financiers. This is the lowest cost method of project implementation with the costs of energy ranging from $87 to $106 per MWh because the developer would be able to take advantage of an investment tax credit (ITC) and utilize the district pre-pay amount to offset the initial project cost.

Sale and Leaseback: The District would build the project and then sell it to a third-party, who would lease the facility back to the District. This method is uncommon for non-taxable entities like the District. The District would take on the financial, project development, and project operation risks with this option. The financing for this method is similar to the PPA method.

As a cost comparison, the PG&E energy costs are in the range of $140 to $160 per MWh and PWRPA energy costs vary from $80 to $100 per MWh. Only the pre-pay PPA development approach would have costs that are competitive with the PWRPA energy costs the District pays for most of its electrical power.

For the three vacant parcels, the study prepared cost estimates for developing the sites to their full potential, and for a smaller project less than 1 MW. For projects less than 1 MW, a rebate through California Solar Initiative might be available.

The study found that developing solar projects on the vacant properties and at the treatment plants is only cost-effective with the pre-pay PPA development approach.

Implementation of Solar Power Recommendations

Based on the results of this study, staff does not plan to pursue any solar projects at these vacant sites. The payback for the Pre-Pay PPA option is nominal with considerable financial risk to the District. If the Board would prefer to invest in solar projects locally, staff recommends including projects at the treatment plants as part of District's Energy Optimization Plan. The benefit to cost ratio for pre-pay PPA development approaches for Penitencia is 1.45 and Santa Teresa is 1.53. The capital costs are about $700,000 for Penitencia and $3.1 million for Santa Teresa.

On-site power generation would help meet on-site power needs, reduce peak demands, provide some redundancy at the plants, and help meet the District's goal of carbon neutrality.

To meet the District's goal of carbon neutrality, staff would consider participation in solar projects in other parts of the state through PWRPA. PWRPA estimates that investments in large-scale renewable energy projects, such as solar power farms in the Central Valley or desert, could cost between $75 to $100 per MWh depending on the technology and site specific costs and benefits.

4. Liquid Fuels

The consultant evaluated alternatives to gasoline and diesel fuel for the District's light duty vehicles, including sedans, SUVs, and trucks (Attachment 4). The analysis did not include heavy duty trucks and equipment, since alternatives to traditional liquid fuel are not currently available for heavy duty vehicles. The assessment primarily consisted of evaluation of the current fuel use; commercially available options for hybrid, electric, and compressed natural gas (CNG) vehicles; associated facilities for each fuel alternative; and required maintenance services for each vehicle type.

The 2012 light duty fleet consisted of 190 vehicles (165 gasoline or diesel vehicles and 25 hybrid vehicles). The assessment of alternative fuel options for the light duty fleet found:

- Commercially available CNG vehicles are currently limited to one model. Traditional gasoline/diesel vehicles can be converted to CNG by third-party vendors. There is limited space for a CNG refueling station in the District maintenance yard. In addition, modifications would need to be made to existing building for maintenance, which would cost up to about $500,000. Staff would also need to be trained on CNG vehicle maintenance.
- Commercially available electric vehicles are limited to cars. There are no commercially available options for SUVs, trucks, or vans. Recharging receptacles could be installed in the existing islands in the pool vehicle parking areas. No building modifications would be needed for electric vehicle maintenance, but staff would need training.
- Hybrid options are available for cars, SUVs, and small trucks. No new refueling facilities are needed for hybrid vehicles. No building modifications would be needed for additional hybrid maintenance and, with one exception; staff is trained for hybrid vehicle maintenance.
- That district continues purchasing hybrid vehicles where possible as part of the fleet replacement program.

Implementation of Liquid Fuels Analysis Recommendations

Staff recommends including the continued purchase of hybrid vehicles as part of the fleet replacement program in the Energy Optimization Plan. As the market for electric vehicles expands, staff will re-evaluate the feasibility of adding electric vehicles to the fleet. CNG vehicles are not recommended at this time given space constraints and costs for additional facilities and training.

Conversion to hybrids for cars, SUVs, and light trucks would yield an estimated 64 percent increase in average fuel economy, from 15.9 miles per gasoline gallon equivalent (GGE) to 26.0 miles per GGE.

5. Anderson Hydroelectric Facility

The consultant evaluated the Anderson Hydroelectric Facility for opportunities to optimize energy generation or lower long-terms costs (Attachment 5). The facility has a generation capacity of 940 kW, but this capacity is seldom achieved because generation is limited by downstream flow needs in Coyote Creek and there are restrictions on using Central Valley Project (CVP) water for power generation. Power generation is also limited by maintenance and repair needs. Both turbines have been rebuilt twice since 2005. Average operations and maintenance costs for the facility are about $60,000 per year. Since 1988, energy generation at the facility averaged 1,318 MWh per year and generated revenue of $109,075 per year.

The key findings from the consultant's evaluation were:

- Due to downstream flow requirements, no immediate capital investments could significantly optimize energy generation at the facility, and
- Operations and maintenance practices can improve energy generation and system reliability.

Options for optimizing energy generation or lowering long-term costs include increased monitoring of facility operations, increased testing of key components, and minimizing the potential for corrosion of the turbines.

Implementation of the Anderson Hydroelectric Facility Recommendations

Staff recommends incorporating the consultant's recommendations for Anderson Hydroelectric Facility in the Energy Optimization Plan. In addition, staff will include facility operations in any evaluation of changes to Coyote Valley water supply operations and CVP contracts.

6. Next Steps

Staff will prepare the Energy Optimization Plan based on the discussion above and Board feedback related to energy optimization, as well as feedback on the staff approach to meet Ends Policy 4.3 regarding carbon neutrality. The Energy Optimization Plan, to be completed by September 2013, will present the District's strategies to conserve energy, improve energy efficiency, and develop additional renewable energy supplies. The plan will provide additional details on recommended projects scopes, budgets, schedules, and benefits related to reducing energy use and greenhouse gas emissions. This information will provide the basis for validating any capital projects. The plan will also include continued monitoring, evaluation, and management of energy use and generation.

Staff will include the recommended projects in the FY15 Capital Improvement Plan and Operating Budget preparation processes. The projects will then be validated and prioritized against other District projects and programs.

FINANCIAL IMPACT:

There is sufficient funding in the district share of PWRPA Trust funds necessary to fund the maximum compensation limit of the consultant agreement, which is for $276,975 including $51,380 for optional services. About $105,000 has been spent to date on the consultant services. Staff spent about 960 hours in FY13 to complete all reports, which includes providing data to the consultant, site visits, review of draft reports, and project management. Staff allocated 400 hours in the proposed FY14 budget to accomplish Energy Optimization Plan.

CEQA:

The recommended action does not constitute a project under CEQA because it does not have a potential for resulting in direct or reasonable foreseeable indirect physical change in the environment.

ATTACHMENTS:

Attachment 1:	Energy Audit Report
Attachment 1A:	Implementation of Energy Audit Recommendations
Attachment 2:	In-Conduit Hydroelectric Generation Report
Attachment 3:	PV Feasibility Study Report
Attachment 4:	Liquid Fuels Report
Attachment 5:	Anderson Hydroelectric Facility Report
Attachment 6:	Power Point Presentation

FINAL

ENERGY OPTIMIZATION PLAN

Energy Audit Report

B&V PROJECT NO. 178292

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PREPARED FOR

Santa Clara Valley Water District

FEBRUARY 2013

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Building a world of difference.

Table of Contents

Executive Summary 1

Summary of Preliminary Energy Analysis 1

Process Facilities Summary 2

Non-Process Building Summary 4

Summary of Level 1 Walk-Through Analysis 6

Treatment Plants 6

Pumping Plants 7

Non-process Buildings 7

Summary and Conclusions 7

1.0 Audit 9

1.1 Audit 9

1.1.1 On-going District Energy Efficiency Improvements 10

1.2 Preliminary Energy Analysis 11

1.2.1 Overview 11

1.2.2 PEA Data Considerations and Assumptions 11

1.2.3 Energy Utilization Index Summary 12

1.3 Summary of Preliminary Energy Analysis 13

1.3.1 Treatment Plants 14

1.3.2 Pumping Plants 14

1.3.3 Industry Data 14

1.3.4 Non-Process Buildings 15

1.4 Level 1 Walk Through Results 20

1.4.1 Water Treatment Plants 21

1.4.2 Pumping Stations 25

1.4.3 Buildings 28

1.4.4 Summary of Level 1 Walk-Through Analysis 29

1.5 Summary and Conclusions 30

LIST OF TABLES

Table ES-1 Process Facility Energy and Cost Intensity Data 2
Table ES-2 SCVWD Building Energy Analysis 5
Table 1-1 Process Facility Energy and Cost Intensity Data 12
Table 1-2 SCVWD Building Meters 16
Table 1-3 SCVWD Building Energy Analysis Based on 2011 Utility Bills 17
Table 1-4 Lawrence Berkeley Lab Office Building Benchmark Analysis for HQ and Admin 19
Table 1-5 Rinconada Energy Conservation Measure Recommendations 21
Table 1-6 Santa Teresa Energy Conservation Measure Recommendations 23
Table 1-7 Penitencia Energy Conservation Measure Recommendations 24
Table 1-8 Pumping Plant Energy Conservation Measure Recommendations 25
Table 1-9 Pacheco Pumping Plant Energy Conservation Measure Recommendations 26
Table 1-10 Vasona Pumping Plant Energy Conservation Measure Recommendations 27
Table1-11 Headquarters Building Energy Conservation Measures Recommendations 28
Table 1-12 Administration Building Energy Conservation Measure Recommendations 29

LIST OF FIGURES

Figure ES - 1 Energy Usage Breakdown 1
Figure ES - 2 Treatment Plant Energy Usage Breakdown 3
Figure ES - 3 Treatment Plant Energy Intensity 3
Figure ES - 4 Pump Station Energy Usage Breakdown 3
Figure ES - 5 Energy Intensity Range by Functional Component (kWh/MG) 4
Figure ES - 6 Non-Process Building Energy Consumption and Cost 5
Figure 1-1 Energy Use Breakdown 13
Figure 1-2 Treatment Plant Energy Use Breakdown 13
Figure 1-3 Treatment Plant Energy Intensity 14
Figure 1-4 Pump Station Energy Use Breakdown 14
Figure 1-5 Energy Intensity Range by Functional Component (kWh/MG) 15
Figure 1-6 Non-Process Building Energy Consumption and Cost 15

ABBREVIATIONS AND ACRONYMS

AHU	Air Handling Unit
ASD	Adjustable Speed Drive
ASHRAE	American Society of Heating, Refrigeration and Air Conditioning Engineers
BEP	Best Efficiency Point
The District	Santa Clara Valley Water District
ECM	Energy Conservation Measure
EPA	Environmental Protection Agency
Floc	Flocculation
HVAC	Heating, Ventilation, and Air Conditioning
kWh	Kilowatt hours
MG	Millions Gallons
MGD	Million Gallons per Day
PG&E	Pacific Gas & Electric
PP	Pumping Plant
SCE	Southern California Edison
SCVWD	Santa Clara Valley Water District
TES	Thermal Energy Storage
USBR	United States Bureau of Reclamation
VFD	Variable Frequency Drive
WTP	Water Treatment Plant

Executive Summary

This report documents the findings of Task 2.1 – The Energy Audit, which focuses on electrical energy use at key load centers of the District. The Audit is organized into two main types of District facilities:

1. Process areas - including the treatment plants and pumping plants
2. Non-process buildings - including the District Headquarters Building, Administration and other minor buildings.

It is important to point out that the report does not include the energy costs associated with the South Bay Aqueduct (SBA), Tracy and O'Neill pumping plants. Although these do represent a significant energy cost for the District, these facilities are not within the control of the District and as a result the District cannot plan or implement energy conservation measures at these facilities.

A key objective of the Audit is to understand where significant energy is used within the District. The approach is also geared to focus the efforts on identifying the "low hanging fruit" or areas of significant energy consumption that can be targeted for further investigation in later tasks of this project. A better picture of where significant energy is used within the District will also aid in the District's overall energy planning efforts.

The audit included the following main activities:

- Preliminary Energy Analysis – including data collection on District energy use and costs
- Level 1 Walkthroughs/brief site visits
- Identification of Energy Conservation Measures

This report summarizes the results of these activities.

It is worthwhile to note that this project is one of the many continuing efforts that the District has in its overall energy efficiency program. The District has an ongoing program of energy conservation efforts that has included: High efficiency motor and Variable Speed Drive Installation, lighting improvements and renewable energy generation (PV) projects, as well as, projects currently underway at Rinconada to install better instrumentation for improved backwash monitoring and control which has potential energy savings.

SUMMARY OF PRELIMINARY ENERGY ANALYSIS

The District utilizes electrical energy and natural gas to power and heat its facilities. This study reviewed the energy consumption at the three water treatment plants Rinconada, Santa Teresa and Penitencia; the three main pumping plants Pacheco, Coyote and Vasona; the two main District office buildings (Headquarters and Administration Buildings) and several minor facilities.

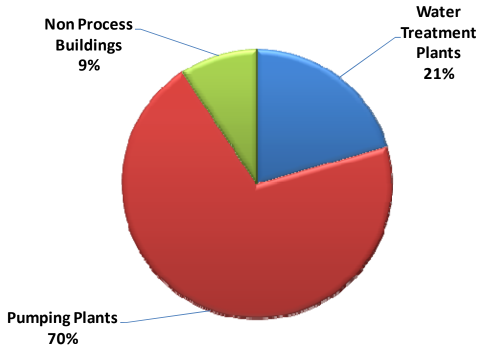

Figure ES - 1 Energy Usage Breakdown

Figure ES-1 provides a summary of the District's average energy use in percentage terms, broken down between treatment plants, pumping plants and non-process buildings. This figure illustrates that the pumping plants are by far the largest energy consumer.

The results of the audit also indicated that the water treatment plants generally represented the highest energy cost, followed by the pumping plants and the non-process buildings with the lowest energy cost at approximately 9% of the total.

Process Facilities Summary

The audit included a review of energy consumption and production data for 2009, 2010 and 2011. These years were considered to be representative of typical years, as a result, extreme wet or dry years as experienced in 2006 and 2007 were excluded from the analysis. Table ES-1 provides a summary of the key energy and production data for the WTPs and the pumping plants.

Table ES-1 Process Facility Energy and Cost Intensity Data

FACILITY	WATER PRODUCTION, MG (2009-2011)	ENERGY USE, KWH (2009-2011)	AVERAGE WATER ENERGY INTENSITY, (KWH/MG) (2009-2011)	AVERAGE ENERGY COST ($/KWH) (2009-2011)	AVERAGE WATER ENERGY COST INTENSITY, $ PER MG (2009-2011)
Penitencia WTP	19,403	5,181,313	267	$0.09	$25
Santa Teresa WTP	42, 879	6,248,477	146	$0.089	$13
Rinconada WTP	48, 712	19,780,025	406	$0.085	$35
Pacheco PP	103,054	91,692,980	890	$0.020	$18
Coyote PP (Project Power)	22,538	10,308,480	457	$0.020	$12
Coyote PP (PWRPA Power)	2,608	778,526	299	$0.11	$33
Vasona PP	1,108	771,510	696	$0.15	$104

The Advanced Water Purification Facility is not included in the audit since it is not scheduled to be in operation until 2013 and does not have any historical operating data. It is estimated to utilize approximately 8.0 M kWh of electrical energy per year if operated at its intended production capacity.

TREATMENT PLANTS

Figure ES-2 provides a percentage breakdown of average electrical energy use (kWh) between the three treatment plants. This shows that the Rinconada plant has the highest energy consumption percentage at 63 percent, followed by Santa Teresa at 20 percent and Penitencia at 17 percent.

Figure ES-3 provides a comparison of average energy intensity for the District's treatment plants. Rinconada uses a significant percentage of the District's treatment plant energy budget and has relatively high energy intensity number when compared to Penitencia and Santa Teresa. One reason for this difference is that Rinconada has treated water pumping. Penitencia and Santa Teresa have no booster pumping.

PUMPING PLANTS

Figure ES-4 shows that approximately 85 % of the total pumping plant energy consumption is at the Pacheco pumping plant with Coyote and Vasona representing small percentages of the total.

The data from the Audit indicates that the District has relatively low per unit electricity costs for the pumping facilities the data shows that the Pacheco PP consumes a significant amount of energy and has a relatively high energy intensity index.

It is worthwhile to point out that the unit cost per kWh is the highest at Vasona due to the limited amount of operation and there are on-going demand and infrastructure costs that increase the average kWh cost. Average values are presented in Table ES-1.

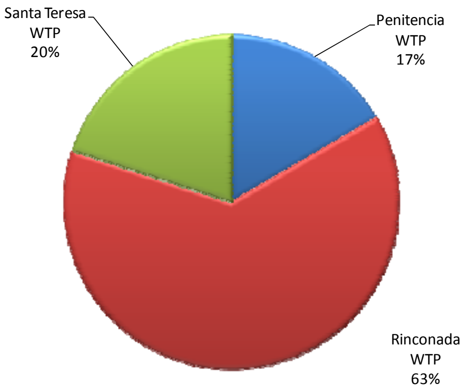

Figure ES - 2 Treatment Plant Energy Usage Breakdown

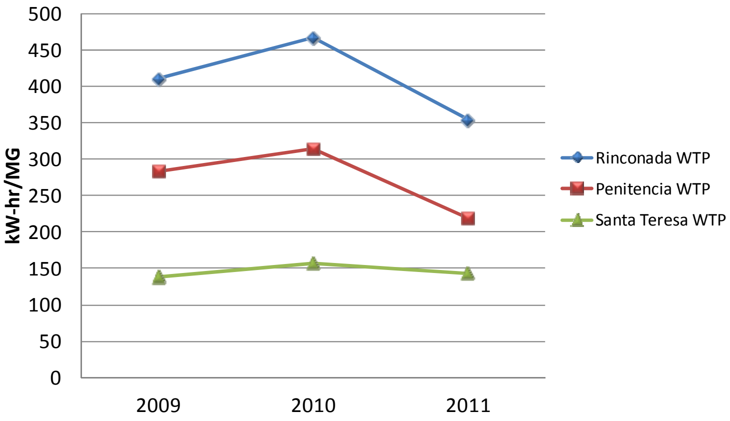

Figure ES - 3 Treatment Plant Energy Intensity

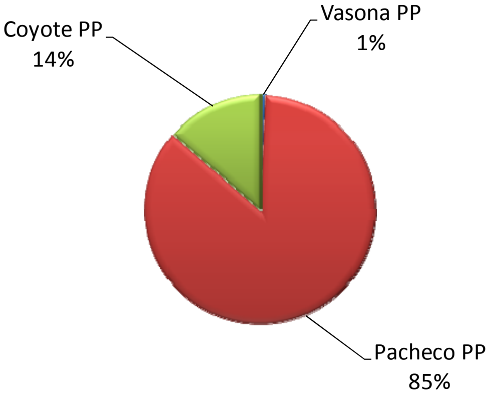

Figure ES - 4 Pump Station Energy Usage Breakdown

INDUSTRY COMPARISONS

Figure ES-5 provides representative values for the energy intensity indexes for similar water treatment and pumping facilities. The data is based on a sampling of PG&E and SCE water utilities in California. The District facilities are identified on the bar chart to show in relative terms where the District facilities fall in regards to the industry ranges. The CPUC report referenced does not provide enough detail for a direct comparison of the efficiency of the District facilities to other similar facilities but does represent the best available data for State of California benchmarks.

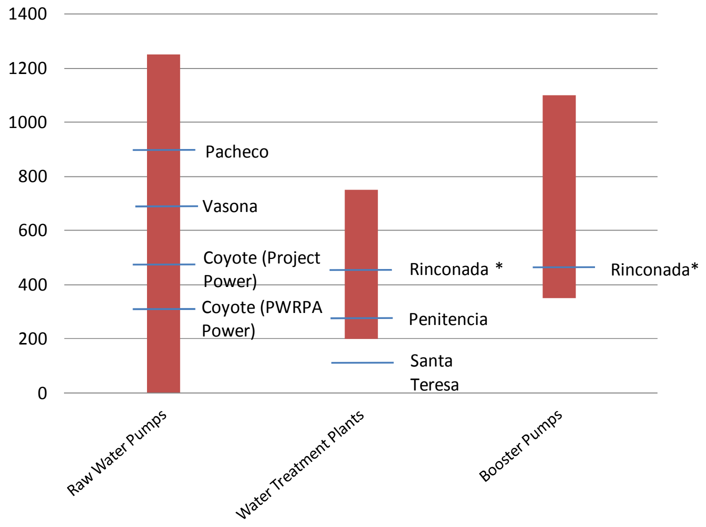

Figure ES - 5 Energy Intensity Range by Functional Component (kWh/MG)

Adapted from: Bennett, et al, August 31, 2012, Embedded Energy in Water Studies Study 2: Water Agency and Function Component Study and Embedded Energy-Water Load Profiles, CPUC, Sacramento, CA

The District's facilities have energy intensity values towards the midpoint or lower range of the industry data, which may provide some indication that the District facilities are operating relatively efficiently.

Rinconada is shown on both the treatment plant range and the booster pump range of values with its total energy intensity value. This will tend to overstate the energy intensity in each category since Rinconada is unique in that it includes treatment as well as finished water boosters. When considered together the overall energy intensity value is about 450 kWh/MG. Preliminary data indicates approximately 55 percent of the total is associated with the pump station and 45 percent associated with the treatment plant portion of the energy use. If these percentages were incorporated into the analysis, the Rinconada energy intensity values in each category would be well below the industry average.

Non-Process Building Summary

The non process buildings included in this study utilize both electrical and thermal energy. As shown previously in Figure ES-1, the non-process buildings utilize approximately 9 percent of the electrical energy consumption at the District.

Figure ES-6 provides non process building energy cost and usage data for the three year period from 2009 to 2011. During this period the non process buildings included in the study had an average annual electricity use of 4,684,925 kWh, with an average annual cost of $440,350.

During this same period the non-process buildings utilized an average of 96,012 therms of natural gas at an average annual cost of $90,665. Electrical energy represents a significantly higher cost than natural gas. The chart shows that annual energy costs for the buildings have been trending down in the last three years.

NON-PROCESS BUILDING PRELIMINARY ENERGY ANALYSIS

Black & Veatch conducted Preliminary Energy Analyses (PEAs) for each non-process building included in the study. An ASHRAE PEA worksheet was developed to analyze each of the eleven buildings on the SCVWD campus using 2011 utility bill information. Energy Usage Index (EUI) and Energy Cost Index (ECI) numbers were calculated for each building and shown in Table ES-2.

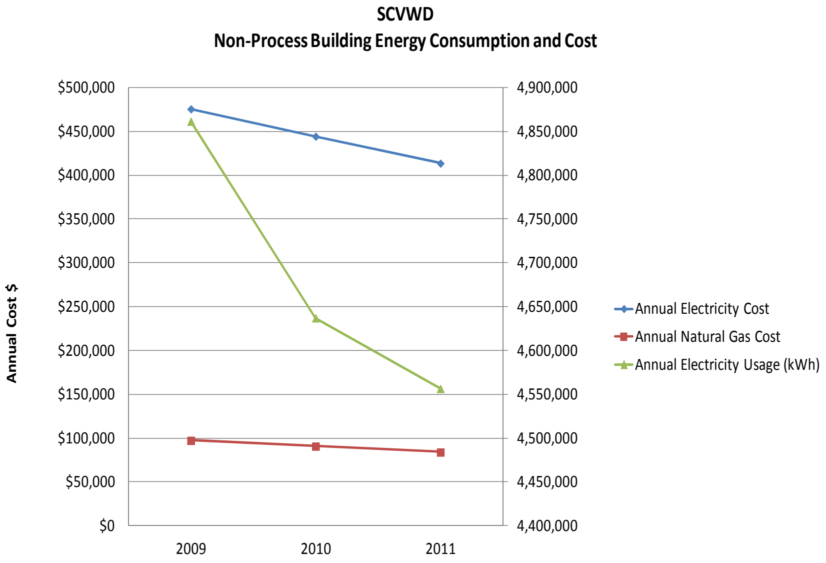

Figure ES - 6 Non-Process Building Energy Consumption and Cost

Table ES-2 SCVWD Building Energy Analysis

FACILITY	METERS		FT^2	EUI (KBTU/FT^2)			ECI ($/FT^2)
	ELECTRIC	GAS		SCVWD	EIA	LBL	
A: Headquarters	HQ	HQ Boiler HQ MO	105,498	89	176	76.8	1.79
B: Administration		Admin	41,294	82	176	76.8	1.73
I: Maintenance Office		OFC&WHSE	13,676	71	176	47	1.63
G: Crest			25,555		176	47	
H: Annex WHSE			4,850		86	14	
D: Maintenance Annex			3,913		176	47	
J: Maintenance Shop			17,135		N/A	25	
W: Water Quality Lab		WQ Lab	23,046	229	N/A	59	3.18
C: Blossom Hill Annex	BH	BH	15,470	50	176	47	1.57
E: Winfield WHSE	WW	WW	40,760	18	86	10	0.51
F: Winfield Mgmt Bldg	WMB	WMB	17,394	22	176	47	0.98

BASELINE DATA COMPARISONS

Industry data was reviewed in order to order to determine how the SCVWD buildings compare in efficiency, relative to other similar facilities in the same geographic area. The US Energy Information Administration (EIA) developed average EUI and ECI values for buildings in the Western United States. This data was published in 2003 and is due for revision sometime in 2012.

Other representative EUI sources were also considered for comparison. Table ES-2 also includes data from the Lawrence Berkeley Lab (LBL) which has developed an online application to compare building energy usage against similar buildings in California. The LBL tool was used to estimate annual energy usage for the headquarters and administration buildings. Estimates were developed for the minor buildings which did not have building-specific metered data available.

The PEA results appear to show that the SCVWD buildings use less energy on average than similar buildings in the western United States when compared to the EIA estimates. The LBL estimates appear to show that the SCVWD HQ and Admin buildings are fifteen percent more energy intensive than peer buildings in central California. Black & Veatch notes that calculations performed on the SCVWD buildings might not reflect the actual energy usage by each building due to multiple buildings being supplied by one meter.

It appears that the Water Quality Lab (WQL) is very energy intensive. The WQL receives electricity from the same meter (HQ) as many of the other buildings on campus, but has a dedicated gas meter. The EUI for the WQL is higher than the other SCVWD buildings due to high gas use. The Water Quality Lab operation has changed to 24/7. The lab requires 100% outside air as well as gas for laboratory process works.

Using this baseline data and the three year average data for the non-process building energy consumption and use, from a high-level conceptual standpoint it is estimated that the District could possibly save 15% of current operating costs at the Headquarters and Administration buildings by enacting energy conservation measures. These savings are not calculated based on an ECM-specific analysis. The remaining buildings on the campus were not visited during this scope of the project. However, energy use across those remaining buildings appears above the average for similar buildings in California. If the 15% savings estimate for the Headquarters and Administration buildings were applied to all buildings on campus, then the following cost savings are expected:

Electricity =703,000 kWh with an average annual cost savings of $66,000.

Natural Gas = 14,000 therms at an average annual cost savings of $13,000.

This may represent an overall potential annual savings opportunity of $79,000.

SUMMARY OF LEVEL 1 WALK-THROUGH ANALYSIS

The Level 1 analysis consisted of walk-throughs of the Major facilities listed above. Level 1 Audits were intended to be preliminary screening audits with the objective of identifying glaring areas of energy waste or inefficiency. The results of the audits we intended to identify low-cost/no-cost measures and potential higher cost improvements that should be considered for further study. A more in depth analysis of a select number of ECMs will be evaluated in later tasks (Task 3.5 and 3.6). The following provides a general description of the best efficiency measures to pursue collectively, and for each major area (pump stations, treatment plants, buildings).

Treatment Plants

Key findings and recommended ECMs for the treatment plants include:

- HVAC modifications and simple thermostatic control modifications

- Review and optimization of backwash controls
- Review of Ozone dosage controls (Penitencia)
- Review and optimization of Rinconada finished water pumping plant

Pumping Plants

Key findings and recommended ECMs for the pumping plants include:

- Evaluation of operating conditions, pumps speeds and control strategies for opportunities to operate the pumps closer to their Best Efficiency Points
- Evaluate drive and motor efficiency combinations
- Provide enhanced power monitoring for enhanced and real time efficiency monitoring

Non-process Buildings

Key findings and recommended ECMs for the non-process buildings include:

- Sub-monitoring of power consumption at the various buildings
- Chiller system review and modification
- Lighting system evaluation

The intent of the level 1 walk throughs was to identify opportunities for energy conservation measure that would be investigated in more detail in later project tasks. As such the cost savings associated with these ECMs were not quantified as a part of the audit.

SUMMARY AND CONCLUSIONS

The Audit supports the following findings:

In general the District energy consumption is concentrated at the Pacheco Pumping Plant, Rinconada treatment plant and the Almaden campus. When compared with industry benchmark data for kWh/MG produced or pumped the District facilities appear to be relatively efficient when compared to industry ranges.

The data indicates that the highest energy intensity index is at the Pacheco Pumping plant however due to the low cost of electrical energy at that plant the cost intensity is relatively low. Even though the cost of energy is inexpensive at Pacheco it does represent a significant component of overall energy consumption at approximately 85 percent of all the energy used for raw water pumping. For purposes of overall energy consumption measures is worthwhile to investigate this facility for efficiency improvements.

The Rinconada WTP has the highest energy consumption and cost intensities of the three treatment plants and produces approximately 46 percent of the total finished water at the District. It is recommended that it be reviewed for additional energy efficiency improvements.

The data also indicates that Penitencia has moderate energy intensity and cost indexes and should be investigated further for energy and cost reduction measures. Even though Penitencia treats a smaller percentage of water than Santa Teresa (which uses the same treatment process), the moderate levels indicate that there may be a greater probability of optimizing the plant to reduce energy consumption.

Based on EIA and LBL calculations the District buildings compared relatively well with other similar buildings in the same geographic area, however there appear to be opportunities at the Almaden campus, and in particular at the Headquarters Building, for energy efficiency improvements.

The audit identified a number of low or moderate cost energy conservation measures at the treatment plants, pumping plants and buildings that the District should consider to improve the efficiency of the facilities.

It is recommended that the operational strategies and facility management be further investigated for additional energy efficiency improvements.

1.0 Audit

This report documents the findings of Task 2.1 – The Audit, which is the targeted electrical energy audit of key load centers. The audit addresses process energy use separately from building energy use. The evaluation included the following major and minor facilities on the District campus as listed below.

1.1 AUDIT

Major facilities:

- Rinconada Water Treatment Plant
- Penitencia Water Treatment Plant
- Santa Teresa Water Treatment Plant
- Pacheco pumping plant
- Vasona pumping plant
- Coyote pumping plant
- Building A – Headquarters Office
- Building B – Administration Office

Minor facilities:

- Building C – Blossom Hill Annex
- Building D - Maintenance Building
- Building E - Winfield Warehouse
- Building F – Winfield Vegetation Management Building
- Building G – Crest
- Building H – Facilities Annex
- Building I – Maintenance Ready Room
- Building J - Shop
- Building W – Water Quality Laboratory

The audit included the following two (2) main elements:

1. A Preliminary Energy Analysis (PEA) was conducted on Major and Minor facilities
2. A Level 1 walk-through analysis was conducted on Major facilities.

In general, ASHRAE energy audit guidelines were followed for these two elements. However, ASHRAE methodologies are not directly applicable to the treatment plants and pumping plants so a modified PEA and Level 1 walk through analysis was conducted for those facilities.

The project approach followed many elements of the EPA guidelines on Water & Energy Efficiency in Water and Wastewater Facilities but were tailored to meet the specific project requirements and scope. The EPA Energy Use Assessment tool was not used in the study since it is more appropriate for a more in-depth audit at the plant and equipment level which was beyond the scope of the study. The presentation of overall energy use and energy intensity indices however is in-line with the EPA guidelines.

It is worthwhile to mention that the audit did not include all energy consumption at the District but was focused on the facilities identified above which are considered ones that represent the majority of energy consumption at the District. Some of the facilities not included are minor utility services for turnouts or metering locations.

It is important to point out that the report does not include the energy costs associated with the South Bay Aqueduct (SBA), Tracy and O'Neill pumping plants. Although these do represent a significant energy cost for the District, these facilities are not within the control of the District and as a result the District cannot plan or implement energy conservation measures at these facilities.

1.1.1 On-going District Energy Efficiency Improvements

It is worthwhile to note that this is one of the many continuing efforts that the District has in its overall energy efficiency program. The District has an ongoing program that has made energy conservation efforts including: high efficiency motor replacements, Variable Speed Drive Installation, insulation and renewable energy generation. The following provides a summary of several of these improvements.

The District implements energy efficiency improvement projects at various District owned facilities. This typically occurs when energy consuming facilities are replaced or rehabilitated. Staff specifies energy efficient devices, equipment, and systems for new projects whenever possible. Premium efficiency motors and adjustable speed drives are specified to reduce pumping related energy consumption.

In 2005, Emcor Energy and Technologies and District staff conducted an energy efficiency site survey (energy audit) at various district facilities and prepared a summary of recommendations for potential energy savings at the Almaden campus, Rinconada Water Treatment Plant, and the Vasona Pumping Station. Staff executed one third of the recommendation. The deviation was caused by both change in operational needs and operating scenarios. For example, More Ave Pump retrofit was scheduled to be included in the RWTP Advanced Treatment Process project and the referenced project is still in planning phase. Staff also replaced motor starters with lower-cost soft starters instead of the recommended variable frequency drives based on the lower operating hours at Vasona Pumping Plant. The following audit recommendations were implemented by the District:

1. Replaced existing less efficient fluorescent lighting fixtures with high efficiency fluorescent lighting fixtures at the Rinconada Water Treatment Plant. ($25K installation cost with 67,934 kWh/year energy reduction).
2. Installed occupancy sensors at Rinconada Water Treatment Plant. ($3k installation cost with 14,914 kWh/year energy saving).
3. Replaced existing outdoor lighting fixtures with more efficient outdoor lighting fixtures at the Almaden campus. ($31K installation cost with 31,812 kWh/year energy reduction).

In addition to implementing the report recommendations, staff implemented the following improvement projects:

1. Replaced booster/backwash pump drive with a high efficiency adjustable speed drive at the Rinconada Water Treatment Plant. ($180K construction cost with 12,945 kWh/year energy reduction).

2. Retrofitted lighting and Heating Ventilation and Air Condition system (HVAC) at the Administration Building. HVAC ductwork has been replaced with insulated ductwork. The HVAC system control was also improved with better zone management and improved air delivery. ($40K construction cost with 31,957 kWh/year energy reduction, natural gas saving is not included).
3. Retrofitted interior light fixture improvements at the Coyote Pumping Station with energy efficient lighting. ($20K construction cost with 1,830 kWh/year energy reduction).

1.2 PRELIMINARY ENERGY ANALYSIS

1.2.1 Overview

The preliminary energy analysis includes a review and tabulation of historical electricity and natural gas energy and cost data based on monthly utility bills provided by the District. The goal of the analysis is to develop a historical baseline of energy use and to develop calculations of water energy intensity and water energy cost intensity.

1.2.2 PEA Data Considerations and Assumptions

The following sections describe several of the assumptions and data quality considerations for the audit.

1.2.2.1 Penitencia, Santa Teresa, Rinconada WTP

- Historical water production based on hourly volumes of water for calendar years 2009 through 2011.
- Electrical energy use based on tabulated monthly PWRPA electrical energy usage (kWh) for calendar years 2009 through 2011.
- Electrical energy cost based on tabulated monthly PWRPA electrical energy costs for calendar years 2009 through 2011.

1.2.2.2 Pacheco Pumping Plant

- Historical water production based on tabulated daily and monthly volumes of pumped water based on flowmeter FI5004 for calendar years 2009 through 2011.
- Electrical energy use based on tabulated monthly “Project Water” electrical energy usage (kWh) for fiscal years 2009 through 2011. Fiscal year includes the following months, October through September. Energy use for October 2011 through November 2011 was not provided as these months will be provided for the 2012 fiscal year. As a result, B&V estimated the electrical usage for these months by averaging the monthly electrical usage for months with similar pumped flow to determine an approximate energy usage for this unavailable data.
- Electrical energy cost based on fiscal year total costs for fiscal years 2009 through 2011. Energy costs for October 2011 through November 2011 were not provided as these months will be provided for the 2012 fiscal year. As a result, B&V estimated the unavailable data by averaging the dollars per kWh for the fiscal years 2009 – 2011.

1.2.2.3 Vasona Pumping Plant

- Electrical energy use based on tabulated monthly PWRPA electrical energy usage (kWh) for calendar years 2009 through 2011.
- Electrical energy cost based on tabulated monthly PWRPA electrical energy costs for calendar years 2009 through 2011.

1.2.2.4 Coyote Pumping Plant

- PWRPA Energy – When pumping raw water to and from Anderson reservoir
  - Electrical energy use based on tabulated monthly PWRPA electrical energy usage (kWh) for calendar years 2009 through 2011.
  - Electrical energy cost based on tabulated monthly PWRPA electrical energy costs for calendar years 2009 through 2011.
- Project Water Energy – When pumping raw water from San Luis reservoir to Santa Clara County
  - Electrical energy use based on tabulated monthly "Project Water" electrical energy usage (kWh) for fiscal years 2009 through 2011. Fiscal year includes the following months, October through September. Energy use for October 2011 through November 2011 was not provided as these months will be provided for the 2012 fiscal year. B&V estimated the electrical usage for these months by averaging the monthly electrical usage for months with similar pumped flow to determine an approximate energy usage for this unavailable data.
  - Electrical energy cost based on fiscal year total costs for fiscal years 2009 through 2011. Energy costs for October 2011 through November 2011 were not provided as these months will be provided for the 2012 fiscal year. As a result, B&V estimated the unavailable data by averaging the dollars per kWh for the fiscal years 2009 – 2011.

1.2.3 Energy Utilization Index Summary

The audit included a review of energy consumption and production data for 2009, 2010 and 2011. These years were considered to be representative of typical years, as a result, extreme wet or dry years as experienced in 2006 and 2007, were excluded from the analysis. Table 1-1 provides a summary of the key energy and production data for the WTPs and the pumping plants.

Table 1-1 Process Facility Energy and Cost Intensity Data

FACILITY	WATER PRODUCTION, MG (2009-2011)	ENERGY USE, KWH (2009-2011)	AVERAGE WATER ENERGY INTENSITY, (KWH/MG) (2009-2011)	AVERAGE ENERGY COST ($/KWH) (2009-2011)	AVERAGE WATER ENERGY COST INTENSITY, $ PER MG (2009-2011)
Penitencia WTP	19,403	5,181,313	267	$0.09	$25
Santa Teresa WTP	42, 879	6,248,477	146	$0.089	$13

FACILITY	WATER PRODUCTION, MG (2009-2011)	ENERGY USE, KWH (2009-2011)	AVERAGE WATER ENERGY INTENSITY, (KWH/MG) (2009-2011)	AVERAGE ENERGY COST ($/KWH) (2009-2011)	AVERAGE WATER ENERGY COST INTENSITY, $ PER MG (2009-2011)
Rinconada WTP	48, 712	19,780,025	406	$0.085	$35
Pacheco PP	103,054	91,692,980	890	$0.020	$18
Coyote PP (Project Power)	22,538	10,308,480	457	$0.020	$12
Coyote PP (PWRPA Power)	2,608	778,526	299	$0.11	$33
Vasona PP	1,108	771,510	696	$0.15	$104

Table 1-1 Process Facility Energy and Cost Intensity Data (cont'd)

The Advanced Water Purification Facility is not included in the audit since it is not scheduled to be in operation until 2013 and does not have any historical operating data. It is estimated to utilize approximately 8.0 M kWh of electrical energy per year if operated at its intended production capacity.

1.3 SUMMARY OF PRELIMINARY ENERGY ANALYSIS

The District utilizes electrical energy and natural gas to power and heat its facilities. This study reviewed the energy consumption at the three water treatment plants Rinconada, Santa Teresa and Penitencia; the three main pumping plants Pacheco, Coyote and Vasona; the two main District office buildings (Headquarters and Administration Buildings) and several minor facilities.

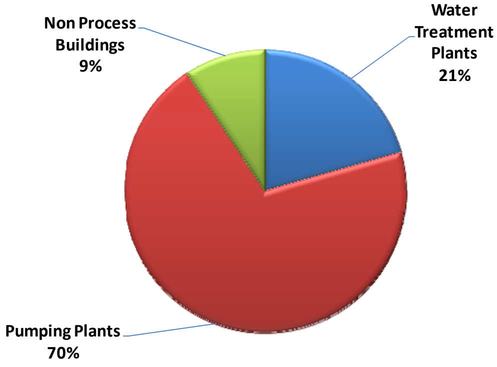

Figure 1-1 Energy Use Breakdown

For the period from 2009 to 2011, the District's average annual electrical energy costs were $2,137,374, and approximately $90,600 in natural gas costs, with natural gas representing approximately 4.0 percent of the total energy costs at the District for the facilities studied.

Figure 1-1 provides a summary of the District's average energy use in percentage terms, broken down between treatment plants, pumping plants and non-process buildings. This figure illustrates that the pumping plants are by far the largest energy consumer.

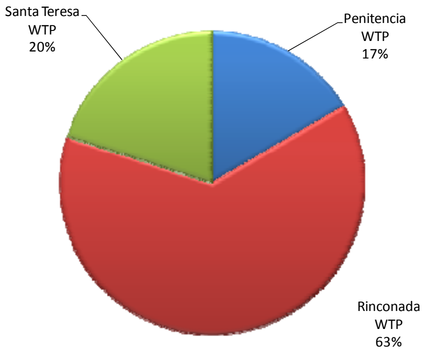

Figure 1-2 Treatment Plant Energy Use Breakdown

1.3.1 Treatment Plants

Figure 1-2 provides a percentage breakdown of average electrical energy use (kWh) between the three treatment plants. This shows that the Rinconada plant has the highest energy consumption percentage at 63 percent, followed by Santa Teresa at 20 percent and Penitencia at 17 percent.

From an efficiency perspective, a key energy metric used for water utility audits is the embedded energy, or energy intensity. The energy intensity is expressed as a measurement of energy used per volume of water produced, typical units are kilowatt hours per million gallons (kWh/MG). This common metric is one included in the EPA guidelines for energy benchmarking for water utilities.

Figure 1-3 provides a comparison of average energy intensity for the District's treatment plants. Rinconada uses a significant percentage of the District's treatment plant energy budget and has relatively high energy intensity number when compared to Penitencia and Santa Teresa. One reason for this difference is that Rinconada has treated water pumping. Penitencia and Santa Teresa have limited amounts of pumping. Additional data shows that approximately 45 percent of the energy at Rinconada is used for the treatment processes and 55 percent for the finished water pumping.

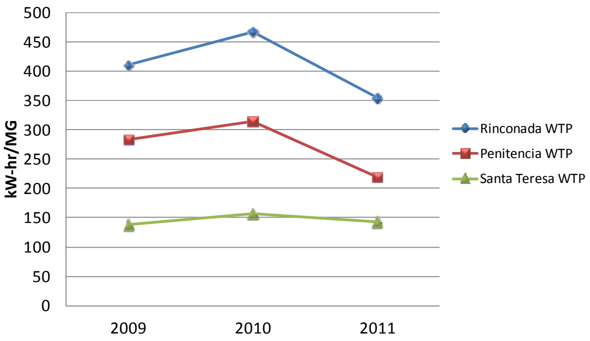

Figure1-3 Treatment Plant Energy Intensity

1.3.2 Pumping Plants

Figure 1-4 shows that approximately 85 % of the total pumping plant energy consumption is at the Pacheco pumping plant with Coyote and Vasona representing small percentages of the total.

The data from the Audit indicates that the District has relatively low per unit electricity costs for the pumping facilities the data shows that the Pacheco PP consumes a significant amount of energy and has a relatively high energy intensity index.

It is worthwhile to point out that the unit cost per kWh is the highest at Vasona due to the limited amount of operation and there are on-going demand and infrastructure costs that increase the average kWh cost. Average values are presented in Table 1-1.

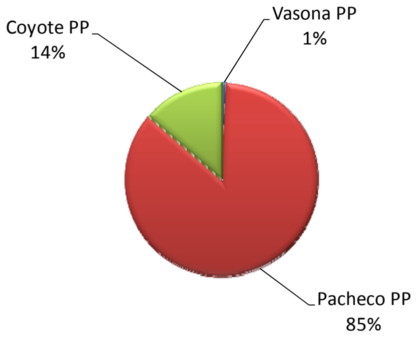

Figure 1-4 Pump Station Energy Use Breakdown

1.3.3 Industry Data

Although the focus of this audit is to establish energy intensity and cost values for the process facilities to be used by the District for tracking of future energy management results, a comparison with industry data for water treatment plants and pumping plants can provide insight into the overall efficiency of the District facilities.

Figure 1-5 provides kWh/MG data from a study that compiled data for water and wastewater facilities throughout California. The CPUC report referenced does not provide enough detail for a direct comparison of the efficiency of the District facilities to other similar facilities but does represent the best available data for State of California benchmarks. The data indicates a range of 100 to 1,250 kWh/MG for Raw Water Pumps, with the Pacheco Pumping Plant having an energy intensity of 483 kWh/MG, would put this facility below the midpoint for this type of facility. The data shows for water treatment plants a range of energy intensity values of 175 to 650 kWh/MG, depending on the type of treatment process. The District treatment plants are in the range of 146kWh/MG for Santa Teresa, to 267 kWh/MG for Penitencia and Rinconada at 406 kWh/MG. This would indicate that the District facilities range from very low energy intensity values to moderately high intensity for Rinconada. It is worthwhile to point out that Rinconada represents a significant percentage of the overall District treated water production.

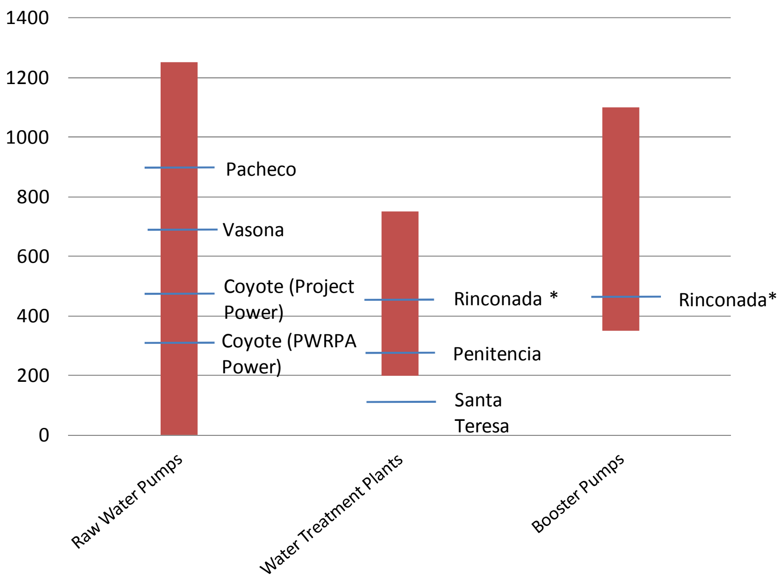

Figure 1-6 Energy Intensity Range by Functional Component (kWh/MG)

Adapted from: Bennett, et al, August 31, 2012, Embedded Energy in Water Studies Study 2: Water Agency and Function Component Study and Embedded Energy- Water Load Profiles, CPUC, Sacramento, CA

1.3.4 Non-Process Buildings

The non process buildings included in this study utilize both electrical and thermal energy. Figure 1-6 provides cost and electrical energy usage data for the three year period from 2009 to 2011. During this period the non process buildings included in the study had an average annual electricity use of 4,684,925 kWh, with an average annual cost of $440,350. During this same period the non-process buildings used natural gas with an average annual cost of $90,665. Electrical energy represents a significantly higher cost than natural gas. The annual cost has been trending

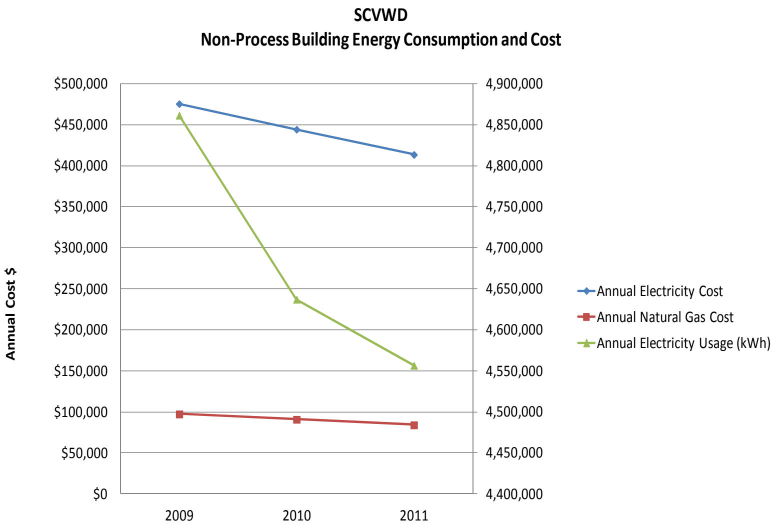

Figure 1-7 Non-Process Building Energy Consumption and Cost

down in the last three years.

1.3.4.1 Building Utility Metering

The individual buildings on the Santa Clara Valley Water District (SCVWD) campus are not all metered individually for gas and electricity. Instead, one electrical meter may serve more than one building and one gas meter may serve more than one building. However, the gas and electric meters do not necessarily serve the same buildings. Table below lists the buildings and the associated gas and electrical meters. Each meter is named and that naming convention is then used in Table 1-2.

All non-process buildings in this section of the report are served by Power and Water Resources Pooling Authority (PWRPA) for electricity and PG&E for gas, with the exception of the Winfield Warehouse and Winfield Management Buildings which report electricity service from both PWRPA and PG&E, but only the PWRPA information was analyzed.

Table 1-2 SCVWD Building Meters

LOCATION	ELECTRICAL METER NUMBER	E-METER NAME	GAS METER NUMBER	GAS METER NAME
A: Headquarters	C-41736	HQ	52522338 2965093X	HQ Boiler HQ MO
B: Administration			47240512	Admin
I: Maintenance Office			39883415	OFC&WHSE
G: Crest				
H: Annex WHSE				
D: Maintenance Annex				
J: Maintenance Shop				
W: Water Quality Lab			60340148	WQ Lab
C: Blossom Hill Annex	C-41739	BH	32473375	BH
E: Winfield Warehouse	C-41738	WW	45569392	WW
F: Winfield Mgmt Bldg	3024R9	WMB		

Black & Veatch created individual Preliminary Energy Analyses (PEAs) for each non-process building included in the study. An ASHRAE PEA worksheet was developed to analyze each of the eleven buildings on the SCVWD campus using 2011 utility bill information. However, since many of the buildings are served by common electric and gas meters, individual energy and cost performance metrics were not able to be calculated for each building. Because of this, the Energy Usage Index (EUI) and Energy Cost Index (ECI) numbers for each building in Table 1-3 are estimated based on the square footage of each building relative to the total square footage of all buildings served by that meter.

1.3.4.2 EUI

EUI, or energy use index, is a unit of measurement that describes a building's energy use. EUI represents the energy consumed by a building relative to its size. A building's EUI is calculated by taking the total energy consumed in one year (measured in kBTU) and dividing it by the total floor space of the building. This includes all sources of energy measured in kBTU and would include a conversion of the electrical energy use into an equivalent amount of thermal energy. Generally, the lower the EUI, the better the energy performance.

Example Calculation

A 40,000 ft^2 building consumes 1,500,000 kWh of electrical energy and 5,900 therms of natural gas per year. The total building energy use in terms of kBTU is calculated as follows:

$$\text{Electricity} \qquad 1{,}500{,}000\ kWh\ X\ 3.412142\ kBTU/kWh = 5{,}118{,}000\ \ kBTU$$

$$\text{Natural gas} \qquad 5{,}900\ therms \quad X\ 100\,\frac{kBTU}{therm} \quad = \quad 590{,}000\ kBTU$$

$$\text{Total Energy Use} \ = 5{,}708{,}000\ \ kBTU$$

$$EUI \ = \ 5{,}708{,}000\ kBTU\ /\ 40{,}000\ ft^2 \ = \ 143\ kBTU/ft^2$$

1.3.4.3 ECI

ECI, or energy cost index, is a unit of measurement that describes a building's energy cost. ECI represents the cost of energy consumed by a building relative to its size. A building's ECI is calculated by taking the total cost of energy consumed in one year (measured in dollars) and dividing it by the total floor space of the building. This includes the cost of all sources of energy.

Table 1-3 SCVWD Building Energy Analysis Based on 2011 Utility Bills

FACILITY	METERS		ft^2	EUI ($kBTU/ft^2$)			ECI ($\$/ft^2$)
	ELECTRIC	GAS		SCVWD	EIA	LBL	
A: Headquarters	HQ	HQ Boiler HQ MO	105,498	89	176	76.8	1.79
B: Administration		Admin	41,294	82	176	76.8	1.73
I: Maintenance Office		OFC& WHSE	13,676	71	176	47	1.63
G: Crest			25,555		176	47	
H: Annex WHSE			4,850		86	14	
D: Maintenance Annex			3,913		176	47	
J: Maintenance Shop			17,135		N/A	25	
W: Water Quality Lab		WQ Lab	23,046	229	N/A	59	3.18
C: Blossom Hill Annex	BH	BH	15,470	50	176	47	1.57
E: Winfield WHSE	WW	WW	40,760	18	86	10	0.51
F: Winfield Mgmt Bldg	WMB		17,394	22	176	47	0.98

Black & Veatch notes that calculations performed on the SCVWD buildings are estimates and likely do not reflect the actual energy usage by each building due to multiple buildings being supplied by one meter. Specifically, it appears that the Water Quality Lab (WQL) is very energy intensive. The WQL receives electricity from the same meter (HQ) as many of the other buildings on campus, but has a dedicated gas meter. The EUI for the WQL is higher than the other SCVWD buildings due to high gas use. The WQL requires 100% outside air and uses gas in its water quality process.

1.3.4.4 Baseline Data Comparisons

Industry data was reviewed in order to order to determine how the SCVWD buildings compare in efficiency relative to other similar facilities in the same general area. Black & Veatch reviewed data published in 2003 by the US Energy Information Administration (EIA), which developed average EUI and ECI values for buildings in the Western United States, and compared those numbers to the SCVWD buildings. This data is referenced by ASHRAE in their PEA spreadsheet tools but is recognized that is generalized and may not provide data that is representative of the SCVWD facilities. In addition, it is recognized that the reference is somewhat dated given it was last updated in 2003 however updated values are scheduled for release sometime in 2012. The PEA results appear to show that the SCVWD buildings use less energy on average than similar buildings in the western United States when compared to the EIA estimates.

Other representative EUI sources were also considered for comparison. Table 1-4 also includes data from the Lawrence Berkeley Lab (LBL) which has developed an online application to compare building energy usage against similar buildings in California[1]. The LBL tool was used to estimate annual energy usage for the headquarters and administration buildings, and estimates were developed for the minor buildings which did not have building-specific metered data available. The LBL estimates appear to show that the SCVWD HQ and Admin buildings are fifteen percent more energy intensive than peer buildings in central California. The LBL analysis parameters used for the HQ and Admin buildings can be found in using this baseline data and the three year average data for the non-process building energy consumption and use from a high-level conceptual standpoint it is estimated that the District could possibly save the following:

Electricity =703,000 kWh with an average annual cost savings of $66,000.

Natural Gas = 14,000 therms with an average annual cost savings of $13,000.

This may represent an overall potential savings of $79,000.

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[1] http://energyiq.lbl.gov/EnergyIQ/benchmark.jsp

Table 1-4 Lawrence Berkeley Lab Office Building Benchmark Analysis for HQ and Admin

Summary	The Site Energy for typical buildings of the type(s) you've specified is 76.8 kBTU/sf-yr [median value], with a range of 67.1 to 76.8 kBTU/sf-yr [5th to 95th percentiles] for the population. Select "Add a Building" button to see how yours compares. Try other Views for graphical and tabular detail. This analysis includes population weights for each building.
Data Set	California only (CEUS)
Location	California= Central Valley
Size	25,001 - 150,000 sf
Vintage	1991 through Present
Type	Administration and Management

1.4 LEVEL 1 WALK THROUGH RESULTS

The Level 1 analysis consisted of walk-throughs of the Major facilities listed above. For the non-process buildings, the walk-throughs in generally followed the ASHRAE guidelines for a Level 1 walk-through. The ASHRAE guidelines were developed for analysis of buildings and do not directly apply to process facilities such as the treatment plants and pumping plants however the general approach was adapted for the process facilities included in the project.

Level 1 Audits are also referred to as simple, screening or walkthrough audits and are the most basic in the ASHRAE guidelines. They involve minimal interviews with plant staff, a brief review of utility bills and other operating data, and a walk through of the facility with the objective of identifying glaring areas of energy waste or inefficiency.

The data gathered is used for the preliminary energy analysis PEA and a report that details low-cost/no-cost measures and potential higher cost improvements that should be considered for further study. The analysis did not include site measurement of operating conditions or characteristics or any modeling of the facilities.

The result of the walk through analysis includes development of a prioritized list of opportunities for further examination in other tasks. The identified opportunities are ranked using qualitative tiers (e.g. high (H), medium (M), low (L)) for the ranking of potential for energy savings and implementation costs. Although the rankings are qualitative the general criteria was used for the rankings:

COST

$0 < Low < $10K

$10K < Medium < $50K

High ≥ $50K

ENERGY SAVINGS

Low < 2 percent

2 percent < Medium <10 percent

High ≥ 10 percent

Energy savings percentages are estimated based on Black & Veatch experience with similar projects and provide an estimate of the order of magnitude of potential savings for a particular type of ECM. It was beyond the scope of the project to do a detailed energy inventory for all items where ECMs were proposed therefore the next step of estimating the actual kWh savings was not completed. The purpose of this task was to identify likely ECMs and a selected number of these will be investigated in more detail in following project tasks (Task 3.5 and 3.6). With that additional data the actual potential savings can be estimated.

Although this provides a relative ranking of the ECMs an additional factor of complexity was used to facilitate the prioritization of the ECMs. The complexity factor is a hidden factor in the rankings and not shown in the tables but takes in to account the level of complexity, schedule or internal buy-in activities that would be needed to complete the ECM. The following sections provide a summary of the Level Audits and the recommended Energy Conservation Measures. Additional notes from the facility walk-throughs are included in Appendix A.

1.4.1 Water Treatment Plants

1.4.1.1 Facility: Rinconada WTP

Date of review: October 10, 2012

1.4.1.1.1 General Comments on the Overall Energy Use and Use By Process Area

Based on field observations and discussions with staff, the largest energy users in the plant are the backwashing system, booster pumping system, plant water system, and other operated equipment such as mixers, solids handling, and the recycle water pumping. Rinconada's building mechanical system was observed to be a higher energy user than in the other water treatment plants because of the larger size of the Operations building.

Some savings may be found in optimizing the backwashing and booster pumping systems by operating pumps at their best efficiency point. Adjustment of backwashing operations may yield energy savings by prolonging filters runs and reducing backwashing. Scheduling intermittent operations, such as filter backwashes, during parts of the day with less-expensive electricity may produce energy cost savings as well. Using the Backwash pump to control clearwell level may provide opportunities for cost savings. It was noted that the District is working on a project to install particle counters on the filters as a means to improve the efficiency of the backwashing process.

Other savings may be found by adjusting the HVAC control settings for the Operations building or by replacing the older HVAC equipment. Although, equipment replacement would incur a higher capital cost. It is unclear whether the HVAC equipment will be upgraded as part of the future water plant upgrades.

Equipment such as facility lighting and small, continuously-operating motors may be replaced or upgraded as part of ongoing, long-term operations and maintenance activities.

Staff also indicated that Rinconada's energy usage is also dependent of the quality of raw water entering the site. Lower quality raw water requires additional chemicals and affects filter operation and increases energy usage.

1.4.1.1.2 Recommended Energy Conservation Measures

Table 1-5 Rinconada Energy Conservation Measure Recommendations

ITEM / RANK	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M, H)	IMPLEMENTATION COST (L, M, H)
1	Investigate filter media backwashing operations to enhance filter runs.	M	L
2	Review flow requirements for the plant water system to see if pressure settings or number of pumps running can be reduced during the day or during periods of low demand	M	L
3	Investigate Operations Building HVAC control settings and temperature adjustment during the day.	L	L
4	Investigate booster pumping system operation and look for	M	L

ITEM / RANK	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M, H)	IMPLEMENTATION COST (L, M, H)
	areas to optimize and to run pumps at their best efficiency.		
5	Reduce backwash operation during peak periods.	L	L
6	Investigate replace older motors on equipment with new motors with higher efficiency where applicable.	M	M
7	Investigate Operations Building HVAC system replacements.	M	H

1.4.1.2 Facility: Santa Teresa Water Treatment Plant

Date of Review: Wednesday, 10 October, 2012

1.4.1.2.1 Overall Facility Description

The Santa Teresa Water Treatment Plant provides a significant amount of the treatment capacity into The District system and effectively provides water to one side of the valley. The plant is located on a hillside and finished water flows by gravity out of the plant.

The plant was constructed in 1989, and the majority of the plant underwent several phases of upgrades in the first half of the 2000s. Operators noted that the backwash pumps are one of the only systems that were not altered in the upgrade projects.

1.4.1.2.2 General Comments on the Overall Energy Use and Use by Process Area

Due to the design of the Santa Teresa WTP water flows through the plant and into the distribution system using gravity and thereby avoiding large pumping systems. The largest energy users in the plant are the ozone systems, the backwash and plant water pumps, and continuously-operating machinery such as mixers and flocculators. There are a large number of motors that operate continuously. Building systems, HVAC, and lighting will also represent a noticeable fraction of overall site energy use, due to the quantity of buildings on site and the low energy requirements of the treatment process.

Adjusting operation of the ozone and backwash systems (with process input), and adjustment of the plant water system may yield some efficiency improvements. Scheduling intermittent operations, such as filter backwashes, during parts of the day with less-expensive electricity may produce energy cost savings. Equipment such as facility lighting and small, continuously-operating motors may be replaced or upgraded as part of ongoing, long-term operations and maintenance activities – as equipment requires replacement, simply replace with higher-efficiency devices.

1.4.1.2.3 Recommended Energy Conservation Measures

Table 1-6 Santa Teresa Energy Conservation Measure Recommendations

ITEM/ RANK	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M,H)	IMPLEMENTATION COST (L, M, H)
1	Investigate Operations Building HVAC control settings.	L	L
2	Prevent plant water pumping system from cycling on and off so often (e.g. – hydropneumatic system tune-up).	M	L
3	Investigate operational changes of the ozone generating system. Operations noted that they have previously worked at maximizing ozone efficiencies; however, the ozone system consumes a large sum of energy and may warrant a follow up investigation of operational changes.	M	L
4	Reduce backwash operation during peak periods. Operations noted they work hard at maximizing the plant filters run times and that backwashing is often performed to support other plant functions.	L	L
5	De-energize equipment not needed	L	L
6	Evaluate the frequency and duration of backwash operations for filter cleaning to see if this can be optimized.	M	M
7	Investigate ways to optimize backwashing pumping operations including operation at BEP.	M	M
8	Replace lights with energy efficient types in Operations Building and around the site.	L	M
9	Replace older motors with new motors with higher efficiency (Example, flocculation mixer motors)	L	M
10	Investigate Operations Building HVAC system replacements.	L	H

1.4.1.3 Facility: Penitencia WTP

Date of review: October 16, 2012

1.4.1.3.1 Overall Facility Description and Approach

Penitencia Water Treatment Plant was built in the mid-1970's. This plant receives raw water primarily from SBA sources. Raw water enters the site through the terminal reservoir and is primarily conveyed by gravity through the various treatment processes. Treated water enters the downstream clearwell and is conveyed to the distribution system by gravity. Water treatment is provided by the following main processes: flash and rapid mixing of chemicals, flocculation basins, sedimentation basins, ozone system, and filter beds. The filter beds are cleaned periodically throughout the day using a backwash pump and air scour.

Staff indicated that Penitencia has had the following upgrades since its original construction: liquid oxygen ozone system and ozone building, backwash pump, new plant water pumps, and newer switchgear.

1.4.1.3.2 General Comments on the Overall Energy Use and Use by Process Area

Water flows through the Penitencia WTP and into the distribution system using gravity and thereby avoiding large pumping systems. The largest energy users in the plant are the ozone systems, the backwash and plant water pumps, and continuously-operating machinery such as mixers and flocculators, due in part to the large number of these machines. Building systems, HVAC, and lighting appeared to represent a smaller fraction of overall site energy use compared to the other District treatment plants because the site buildings were smaller and the Ozone Building included newer HVAC equipment.

Adjusting operation of the ozone and backwash systems (with process input), and adjustment of the plant water system may yield some efficiency improvements. Scheduling intermittent operations, such as filter backwashes, during parts of the day with less-expensive electricity may produce energy cost savings as well. Using VFD control for pumping systems rather than valve throttling would also provide cost savings, but would include higher capital cost. Other energy savings may be found by adjusting HVAC control settings and optimizing the Ozone Generator room cooling air flow.

Equipment such as facility lighting and small, continuously-operating motors may be replaced or upgraded as part of ongoing, long-term operations and maintenance activities – as equipment requires replacement, simply replace with higher-efficiency devices.

1.4.1.3.3 Recommended Energy Conservation Measures

Table 1-7 Penitencia Energy Conservation Measure Recommendations

ITEM/ RANK	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M, H)	IMPLEMENTATION COST (L, M, H)
1	Investigate Ozone Generation Building HVAC control settings.	L	L
2	Investigate Ozone Generation Building air flow.	L	L
3	De-energize equipment not needed	L	L
4	Investigate plant water pumping system to utilize newer pumps.	M	L
5	Investigate operational changes of the ozone generating system. Operations noted that the system is operated to deliver the proper doze of ozone for disinfection, taste and odor control of the finished water; however, the ozone system consumes a large sum of energy and may warrant a follow up investigation of operational changes.	M	L
6	Reduce backwash operation during peak periods. Operations noted that storage capacity and pumping capacity for backwashing may limit flexibility.	L	L
7	Replace older motors with new motors with higher efficiency (Example, rapid and flocculation mixer motors)	L	M
8	Investigate using VFD on reclaim pump instead of throttling valve to control flow.	L	M

1.4.2 Pumping Stations

1.4.2.1 Facility: Coyote Pumping Plant

Date of review: October 16, 2012

1.4.2.1.1 Overall Facility Description and Approach

The Coyote Pumping plant consists of 6 horizontal centrifugal pumps that act as booster pumps to Pacheco when flow is greater than 160 ± cfs. Pumping plant is also operated to keep Anderson Reservoir water level below Division of Safety of Dams (DSOD) restricted level and to drain the reservoir to make room for future water storage. The pumping plant has also been used to provide water to the system during the various rehabilitation work being done on the transmission system when specific sections of the system are shutdown due to the construction. Operators indicated the pumping plant must always be on-line in case the pumps are needed.

1.4.2.1.2 Recommended Energy Conservation Measures

Table 1-8 Pumping Plant Energy Conservation Measure Recommendations

ITEM/ RANK	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M, H)	IMPLEMENTATION COST (L, M, H)
1	Investigate Electrical Room HVAC control settings.	L	L
2	Evaluate whether or not the pumps and associated electrical equipment (drives, xfmrs) can be de-energized during non use periods for the Coyote PS	M	L
3	Investigate optimizing air cooling flow in the Electrical Room	L	L
4	Investigate pump curves and system operation to optimize pumping efficiency.	M	L
5	Provide Operators via SCADA a display of wire to water efficiency for the pumping plant. This will allow for feedback on strategies that have an impact on energy use.	M	L
6	Install occupancy sensors on lighting systems to turn off fluorescent lights when building is unoccupied.	L	L
7	Investigate replacing existing lights w/ high energy efficient ones	L	M
8	Investigate HVAC system replacements.	L	H
9	Evaluate installation of higher efficiency variable speed drives	L	H

1.4.2.2 Facility: Pacheco Pumping Plant

Date of Review: Thursday, 11 October, 2012

1.4.2.2.1 Overall Facility Description

The pumping plant was commissioned in 1986. It draws water from the San Luis Reservoir and lifts the water to the regulating tank which then flows by gravity to the San Felipe water system (towards Santa Clara) and the Hollister water system (to San Justo Reservoir).

The pumping plant is owned by the Bureau of Reclamation, and operated and maintained by The District. Electricity for the pumping plant is "Project Power" produced by the Bureau, and wheeled by the Western Area Power Administration (WAPA). The cost of electricity through this arrangement is low and in the range of $0.02/kWh. SCVWD does not pay the electricity costs directly; the cost of electricity is a component of the charge per acre-foot paid by The District to the Bureau. Because of these arrangements, The District will not immediately realize cost savings from any energy conservation measures implemented at the pumping plant unless elements of the contract with the Bureau are adjusted or renegotiated.

The pumping plant is generally un-manned.

There is an ASD replacement project currently underway to replace the original slip-recovery drives.

1.4.2.2.2 General Comments on the Overall Energy Use and Use By Process Area

Energy use at the Pacheco pumping plant is essentially from the twelve large pumps. Attempting to control the pumps to operate at their Best Efficiency Point is likely to be one of the largest areas for energy savings in this facility. Relatively minor energy savings may also be found within the lighting and heating/cooling systems, but these savings will be very small when compared to overall facility energy use.

1.4.2.2.3 Recommended Energy Conservation Measures

Table 1-9 Pacheco Pumping Plant Energy Conservation Measure Recommendations

ITEM/ RANK	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M, H)	IMPLEMENTATION COST (L, M, H)
1	Investigate optimizing air cooling flow in the Electrical Room	L	L
2	Investigate pump curves and system operation to optimize pumping efficiency by operating pumps at Best Efficiency Point.	M	L
3	Provide Operators via SCADA a display of wire to water efficiency for the pumping plant. This will allow for feedback on strategies that have an impact on energy use.	M	L
4	Replace lights with energy efficient types.	L	M

1.4.2.3 Facility: Vasona Pumping Plant

Date of Review: Thursday, 11 October, 2012

1.4.2.3.1 Overall Facility Description

The pumping plant was constructed in the 1970s. It is located at the intersection of the Almaden Valley Pipeline, the Central Pipeline, and the Rinconada Force Main. One of the pumping plant functions is to provide raw water through the Almaden pipeline when SBA source water is not available. Vasona has also historically been used in the Fall (usually October or November) to bring in SBA water. The location of the pumping plant among the various pipelines combined with the valving arrangement provides operational flexibility for pumping water in several directions.

The pump station is rarely used except when there is a planned pipeline shutdown or during an emergency. The last time the pump station operated was when the Almaden pipeline was shutdown and the Vasona pump station was used to pump water to Rinconada WTP.

The pump station is generally unmanned, but personnel are often nearby because other facilities are located on the same site, including the meter shop and valve yard.

Typical full-site electrical demand is approximately 30kW without the pump station operating. Staff estimates about one week of operation per year in aggregate. This operational scenario will tend to limit the savings that can be achieved by implementing energy conservation measures.

1.4.2.3.2 General Comments on the Overall Energy Use and Use by Process Area

Because the pumps at the Vasona pumping plant rarely operate, the majority of the ongoing energy loads are in the lighting and heating/cooling systems. Adjustments to lighting and HVAC systems may produce energy efficiency gains that are small in overall magnitude, but more significant in the context of this facility compared to the other District process facilities.

1.4.2.3.3 Recommended Energy Conservation Measures

Table 1-10 Vasona Pumping Plant Energy Conservation Measure Recommendations

ITEM	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M, H)	IMPLEMENTATION COST (L, M, H)
1	Check setpoints of gas unit heaters to avoid over-heating this typically unoccupied building.	L	L

1.4.3 Buildings

This section summarizes the findings from the non-process building Level 1 walkthroughs of the Almaden Headquarters and Administration Building.

1.4.3.1 Facility: Headquarter Office Building

Date of review: October 2, 2012

1.4.3.1.1 Overall Facility Description and Approach

The District Headquarters (HQ) office building was constructed from 1997-2000 with occupation starting in 2000. The facility is three stories tall and houses offices and conference rooms, as well as, a large board room. Approximately three hundred employees regularly work in the HQ building with flexible work schedules that allow them to take Mondays or Fridays off every other week. The building also contains a small cafeteria and a data center.

HVAC is provided through a centralized water-cooled chiller system and a centralized heating water system. Five air handlers are mounted in a roof penthouse to supply various zones within the building. A central atrium that extends through each story makes it difficult to measure return air temperatures that would typically be monitored to control air supply temperature, so floor temperature sensors are averaged to determine supply air temperatures. VFDs are used on the various HVAC fans, but no VFDs have been incorporated into the chilled or heating water systems.

1.4.3.1.2 Recommended Energy Conservation Measures

The result of the walk through analysis includes development of a prioritized list of opportunities for further examination in other tasks.

Table1-11 Headquarters Building Energy Conservation Measures Recommendations

ITEM	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M, H)	IMPLEMENTATION COST (L, M, H)
1	Add hot water reset to boiler	M	L
2	Replace outdoor lighting with equivalent compact fluorescent technologies	H	M
3	Replace existing HVAC control system with same as used throughout the rest of the campus	H	M
4	Add VFDs on chilled and heating water pumping systems	H	M
5	Add cooling tower optimization	M	M
6	Replace T8 lighting with T5 lighting	L	M
7	Replace lighting controls system	M	M
8	Add CO2 sensors to control intake air percentage	M	M
9	Install sub-metering for the individual buildings fed by the Headquarters Bldg service to support detailed evaluation of building energy use	L	H
10	Replace chiller	L	H
11	Replace Boiler (operational issue)	L	H

1.4.3.2 Facility: Administration Building

Date of review: October 2, 2012

1.4.3.2.1 Overall Facility Description and Approach

The Administration building was built in the 1970s and has undergone multiple capital improvements over its lifetime. The building is built on a concrete slab, is two stories tall and uses single pane windows with tint. The building houses a data center and has a backup generator that can power the data center and associated HVAC systems. Capital improvements occurred in 2005 which resulted in new chillers for the HVAC system and new air handler units with VFDs. The chilled water pumping systems were also updated at this time to include VFDs.

It is apparent from these energy usage numbers that while the Admin building is operating at lower energy usage rates than similar buildings in the western United States, it is operating at a higher energy usage than peer buildings in central California. Peer buildings in central California are a more representative comparison for the SCVWD buildings due to similar weather conditions and building codes.

1.4.3.2.2 Recommended Energy Conservation Measures:

The result of the walk through analysis includes development of a prioritized list of opportunities for further examination in other tasks.

Table 1-12 Administration Building Energy Conservation Measure Recommendations

ITEM	DESCRIPTION	ENERGY SAVINGS POTENTIAL (L,M, H)	IMPLEMENTATION COST (L, M, H)
1	Add hot water reset to boiler	M	L
2	Replace outdoor lighting with equivalent compact fluorescent technologies	L	M
3	Add CO2 sensors to control intake air percentage	M	M
4	Add chiller optimization	M	M
5	Install sub-metering for the individual buildings to support detailed evaluation of building energy use	L	M

1.4.4 Summary of Level 1 Walk-Through Analysis

The Level 1 analysis consisted of walk-throughs of the Major facilities listed above. Level 1 Audits were intended to be preliminary screening audits with the objective of identifying glaring areas of energy waste or inefficiency. The results of the audits we intended to identify low-cost/no-cost measures and potential higher cost improvements that should be considered for further study. A more in depth analysis of a select number of ECMs will be evaluated in later tasks (Task 3.5 and 3.6). The following provides a general description of the best efficiency measures to pursue collectively, and for each major area (pump stations, treatment plants, buildings).

1.4.4.1 Treatment Plants

Key findings and recommended ECMs for the treatment plants include:

- HVAC modifications and simple thermostatic control modifications
- Review and optimization of backwash controls
- Review of Ozone dosage controls (Penitencia)
- Review and optimization of Rinconada finished water pumping

1.4.4.2 Pumping Plants

Key findings and recommended ECMs for the pumping plants include:

- Evaluation of operating conditions, pumps speeds and control strategies for opportunities to operate the pumps closer to their Best Efficiency Points
- Evaluate drive and motor efficiency combinations
- Provide enhanced power monitoring for enhanced and real time efficiency monitoring

1.4.4.3 Non-process Buildings

Key findings and recommended ECMs for the non-process buildings include:

- Sub-monitoring of power consumption at the various buildings
- Chiller system review and modification
- Lighting system evaluation

1.5 SUMMARY AND CONCLUSIONS

The Audit supports the following findings:

In general the District energy consumption is concentrated at the Pacheco Pumping Plant, Rinconada treatment plant and the Almaden campus. When compared with industry benchmark data for kWh/MG produced or pumped the District facilities appear to be relatively efficient when compared to industry ranges.

The data indicates that the highest energy intensity index is at the Pacheco Pumping plant however due to the low cost of electrical energy at that plant the cost intensity is relatively low. Even though the cost of energy is inexpensive at Pacheco it does represent a significant component of overall energy consumption at approximately 86 percent of all the energy used for raw water pumping. For purposes of overall energy consumption measures is worthwhile to investigate this facility for efficiency improvements.

The Rinconada WTP has the highest energy consumption and cost intensities of the three treatment plants and produces approximately 46 percent of the total finished water at the District. It is recommended that it be reviewed in for additional energy efficiency improvements.

The data also indicates that Penitencia has moderate energy intensity and cost indexes and should be investigated further for energy and cost reduction measures. Even though Penitencia treats a smaller percentage of water than Santa Teresa (which uses the same treatment process), the moderate levels indicate that there may be a greater probability of optimizing the plant to reduce energy consumption.

Based on EIA and LBL calculations the District buildings compared relatively well to western US peer buildings; however, a more accurate comparison is to central California specific buildings which show that the Headquarters building is operating at higher energy usage rates. Overall, there appear to be opportunities at the Almaden campus, and in particular at the Headquarters Building, for energy efficiency improvements.

The audit identified a number of low or moderate cost energy conservation measures at the treatment plants, pumping plants and buildings that the District should consider to improve the efficiency of the facilities.

It is recommended that the operational strategies and facility management be further investigated for additional energy efficiency improvements.

Attachment - 1A
Implementation of Energy Audit Recommendations

NO.	DESCRIPTION	ENERGY SAVING	IMPLEMENTATION COST	IMPLEMENTATION OPTIONS RECOMMENDED BY STAFF
PACHECHO PUMPING PLANT				
1	Investigate optimizing air cooling flow in the Electrical Room	L	L	Needs further analysis
2	Investigate pump curves and system operation to optimize pumping efficiency by operating pumps at Best Efficiency Point.	M	L	Implement
3	Provide Operators via SCADA a display of wire to water efficiency for the pumping plant. This will allow for feedback on strategies that have an impact on energy use.	M	L	Implement
4	Replace lights with energy efficient types.	L	M	Needs further analysis
RINCONADA WATER TREAMENT PLANT				
1	Investigate filter media backwashing operations to enhance filter runs.	M	L	Implement
2	Review flow requirements for the plant water system to see if pressure settings or number of pumps running can be reduced during the day or during periods of low demand	M	L	Completed
3	Investigate Operations Building HVAC control settings and temperature adjustment during the day.	L	L	Implement
4	Investigate booster pumping system operation and look for areas to optimize and to run pumps at their best efficiency.	M	L	Completed
5	Reduce backwash operation during peak periods.	L	L	Not to be implemented
6	Investigate replace older motors on equipment with new motors with higher efficiency where applicable.	M	M	Implement
7	Investigate Operations Building HVAC system replacements.	M	H	Needs further analysis

Attachment - 1A
Implementation of Energy Audit Recommendations

NO.	DESCRIPTION	ENERGY SAVING	IMPLEMENTATION COST	IMPLEMENTATION OPTIONS RECOMMENDED BY STAFF
HEADQUARTER BUILDING				
1	Add hot water reset to boiler	M	L	Completed
2	Replace outdoor lighting with equivalent compact fluorescent technologies	H	M	Needs further analysis
3	Replace existing HVAC control system with same as used throughout the rest of the campus	H	M	Implement
4	Add VFDs on chilled and heating water pumping systems	H	M	Implement
5	Add cooling tower optimization	M	M	Needs further analysis
6	Replace T8 lighting with T5 lighting	L	M	Needs further analysis
7	Replace lighting controls system	M	M	To be implemented
8	Add CO2 sensors to control intake air percentage	M	M	Needs further analysis
9	Install sub-metering for the individual buildings fed by the Headquarters Bldg service to support detailed evaluation of building energy use	L	H	Completed
10	Replace chiller	L	H	Needs further analysis
11	Replace Boiler (operational issue)	L	H	Implement
ADMINISTRATION BUILDING				
1	Add hot water reset to boiler	M	L	Completed
2	Replace outdoor lighting with equivalent compact fluorescent technologies	L	M	Needs further analysis
3	Add CO2 sensors to control intake air percentage	M	M	Not to be implemented
4	Add chiller optimization	M	M	Needs further analysis
5	Install sub-metering for the individual buildings to support detailed evaluation of building energy use	L	M	Completed

FINAL

ENERGY OPTIMIZATION PLAN

In-conduit Hydro Generation Evaluation

B&V Project No.178292

Prepared for

Santa Clara Valley Water District

FEBRUARY 2013

BLACK & VEATCH

Table of Contents

Executive Summary 1
In-Conduit Hydro Generation Evaluation 1
1.0 Introduction 3
2.0 Evaluation Methodology 3
3.0 Candidate Site Evaluations 6
3.1 Treated Water Candidate Site Evaluations 6
3.1.1 Hostetter Turnout 6
3.2 Ocala Turnout 8
4.3.3 Alum Rock Turnout 10
4.3.4 Pinos Turnout 12
4.3.5 Skyway Turnout 14
4.3.6 Santa Clara Turnout 15
4.3.8 Congress Turnout 18
4.4 Raw Water Candidate Site Evaluations 20
4.4.1 Half Road and Madrone Turnout 20
4.4.2 Uvas Reservoir Outlet 21
4.4.3 Vasona 805 Valve 22
4.4.4 Calero Modulation Valve 24
4.4.5 Peet Road Valve 26
4.5 Evaluation Conclusions 28

LIST OF FIGURES

Figure 1 Photo of Hostetter Turnout Site 6
Figure 2 Hostetter Flow Duration Curve 6
Figure 3 Aerial Photo of Ocala Turnout Site 8
Figure 4 Ocala Flow Duration Curve 8
Figure 5 Photo of Alum Rock Turnout 10
Figure 6 Alum Rock Flow Duration Curve 10
Figure 7 Aerial Photo of Pinos Turnout Site 12
Figure 8 Pinos Flow Duration Curve 12
Figure 9 Photo of Skyway Turnout Site 14
Figure 10 Skyway Flow Duration Curve 14
Figure 11 Santa Clara Aerial View 15
Figure 12 Santa Clara Flow Duration Curve 15
Figure 13 Cox Aerial View 17
Figure 14 Cox Flow Duration Curve 17
Figure 15 Aerial Photo of Congress Turnout Site 18
Figure 16 Congress Flow Duration Curve 18
Figure 17 Aerial Photo of Half Road and Madrone Turnout Site 20
Figure 18 Half Road and Madrone Flow Duration Curve 20
Figure 19 Aerial Photo of the Uvas Reservoir Outlet Site. 21
Figure 20 Uvas Reservoir Flow Duration Curve. 21
Figure 21 Vasona Aerial View 22
Figure 22 Vasona 805 Valve Flow Duration Curve 23
Figure 23 Aerial Photo of Calero Modulation Valve Site 24
Figure 24 Calero Modulation Valve Flow Duration Curve 24
Figure 25 Aerial Photo of Peet Road Valve Site 26
Figure 26 Peet Road Valve Flow Duration Curve 26

LIST OF TABLES

Table 1 Summary of Evaluation Conclusions. 2
Table 2 Hostetter Turnout Hydro Generation Evaluation Summary. 7
Table 3 Ocala Hydro Generation Evaluation Summary. 8
Table 4 Alum Rock Turnout Hydro Generation Evaluation Summary. 10
Table 5 Pinos Turnout Hydro Generation Evaluation Summary. 13
Table 6 Skyway Hydro Generation Evaluation Summary. 14
Table 7 Santa Clara Hydro Generation Evaluation Summary. 16
Table 8 Cox Hydro Generation Evaluation Summary. 17
Table 9 Congress Hydro Generation Evaluation Summary. 19

Table 10 Half Road and Madrone Turnout Hydro Generation Evaluation. 20
Table 11 Uvas Reservoir Outlet Hydro Generation Evaluation Summary. 21
Table 12 Vasona 805 Valve Hydro Generation Evaluation Summary......................... 23
Table 13 Calero Modulation Valve Hydro Generation Evaluation Summary........... 25
Table 14 Peet Road Valve Hydro Generation Evaluation Summary. 26
Table 15 Treated Water Sites Summary of Conclusions for the Hydro Generation Evaluation. 28
Table 16 Raw Water Sites Summary of Conclusions for the Hydro Generation Evaluation. 31

Executive Summary

IN-CONDUIT HYDRO GENERATION EVALUATION

In support of the District's Energy Optimization Plan this report provides an assessment of the potential for in-conduit hydro electric generation opportunities within the District's Raw and Treated Water pipelines. The focus of the assessment is to identify candidate sites that have potential for cost effective in-conduit hydroelectric energy generation. The assessment also included a review of potential operational changes to improve the overall efficiency by putting less energy into the system.

This evaluation included an initial screening step to identify locations within the District pipelines where differential pressure and flow conditions occur at levels that would make in-conduit hydro a cost effective option. Historical flow and pressure data was obtained from the District's SCADA system for the analysis. Using screening criteria developed by B&V and the historical data, the District identified 41 sites within the raw and treated water piping networks for evaluation of their potential for in-conduit energy recovery. Out of the 41 potential sites initially investigated 13 were identified for further investigation for their hydro power generation potential. These 13 sites were then assessed with a high level evaluation process to determine the estimated planning level development costs and projected revenue.

The evaluation considered the following primary criteria in making the feasibility determination of each site:

- Annual energy production potential
- Total construction costs, implementation costs, annual operations and maintenance costs, and additional costs due to site-specific constraints.
- Potential revenue projected over a 50 year period and estimated Net Present Value (NPV) of savings both with and without California based Green Energy incentives.

Evaluation Conclusions

The evaluation concluded that each site was either feasible without Green Energy incentives, only feasible with Green Energy incentives or is not economically feasible for in-conduit hydro generation. All Treated Water sites were reviewed at different downstream pressures to determine what impact downstream operating pressure of the in-conduit devices has on the Net Present Value of savings. The downstream pressures evaluated were based on discussions with District Operations staff and a review of hydraulic conditions for each of the facilities.

Table 1 below summarizes the findings of this evaluation in order of highest to lowest Net Present Value for each alternative identified in the column.

Table 1 Summary of Evaluation Conclusions.

FEASIBLE WITHOUT GREEN ENERGY INCENTIVES	ONLY FEASIBLE WITH GREEN ENERGY INCENTIVES	NOT ECONOMICALLY FEASIBLE
Hostetter Turnout Buried with downstream pressures of 20 psi	**Pinos Turnout** Buried facility with downstream pressure of 40 psi	**Skyway Turnout** Buried facility with downstream pressures of 80 psi
Hostetter Turnout Buried with downstream pressures of 40psi	**Half Road and Madrone Turnout**	**Cox Turnout** Above ground facility with downstream pressure of 20 psi
Alum Rock Turnout Above ground facility with downstream pressures of 20 psi	**Hostetter Turnout** Buried with downstream pressure of 80psi	**Pinos Turnout** Buried facility with downstream pressures of 80 psi
Ocala Turnout Above ground facility with downstream pressures of 20 psi	**Santa Clara Turnout** Above ground facility with downstream pressures of 40 psi	**Santa Clara Turnout** Above ground facility with downstream pressure of 80 psi
Pinos Turnout Above ground facility with downstream pressure of 20 psi	**Vasona 805 Valve** With a Francis type turbine	**Cox Turnout** Buried facility with downstream pressure of 20 psi
Skyway Turnout Buried facility with downstream pressures of 20 psi	**Uvas Reservoir Outlet**	**Cox Turnout** Above ground facility with downstream pressure of 40 psi
Alum Rock Turnout Buried facility with downstream pressures of 20 psi	**Ocala Turnout** Above ground facility with downstream pressure of 80 psi	**Congress Turnout** Above ground facility with Downstream pressure 20 psi
Ocala Turnout Buried facility with downstream pressures of 20 psi	**Alum Rock Turnout** Above ground facility with downstream pressures of 80 psi	**Congress Turnout** Above ground facility with Downstream pressure of 40 psi
Pinos Turnout Buried facility with downstream pressures of 20 psi	**Ocala Turnout** Buried facility with downstream pressures of 80 psi	**Cox Turnout** Buried facility with downstream pressure of 40 psi
Alum Rock Turnout Above ground facility with downstream pressures of 40 psi	**Alum Rock Turnout** Buried facility with downstream pressure of 80 psi	**Congress Turnout** Buried facility with downstream pressure of 40 psi
Ocala Turnout Above ground facility with downstream pressures of 40 psi	**Pinos Turnout** Above ground facility with downstream pressures of 80 psi	**Congress Turnout** Buried facility with downstream pressure of 20 psi
Pinos Turnout Above ground facility with downstream pressures of 40 psi		**Calero Modulation Valve**
Skyway Turnout Buried facility with downstream pressure of 40 psi		**Peet Road Valve**
Santa Clara Turnout Above ground facility with downstream pressures of 20 psi		**Vasona 805 Valve** With a Kaplan type turbine
Ocala Turnout Buried facility with downstream pressure of 40 psi		
Alum Rock Turnout Buried facility with downstream pressure of 40 psi		

1.0 Introduction

SCVWD's economic and environmental goals have led the District to develop an Energy Optimization Plan. In support of the District's plan, this report provides an assessment of the potential for in-conduit hydro electric generation opportunities within the District's Raw and Treated Water pipelines. The focus of the assessment is to identify candidate sites that have potential for cost effective energy generation.

As part of this effort, the District identified forty-one (41) sites within the raw and treated water piping networks for evaluation of the potential for in-conduit energy recovery. Each of these sites was initially screened based on their available differential pressure (head), historic flow magnitude and theoretical power output.

As part of the Energy Optimization Plan, operational changes were investigated to identify if any effort could be made to reduce energy input into the system where flow and head was high enough to consider in-conduit hydro generation. All SCVWD sites included in the following report were investigated but could not be lowered further through operational changes.

Photos of the site locations and infrastructure drawings were also provided for sites determined by SCVWD to hold the most promise. These were used to aid in the determination of the viability for in-conduit hydro power generation.

This Technical Memorandum presents the results of an in-conduit hydro generation evaluation for the Raw and Treated Water pipeline systems of the SCVWD system. The evaluation included the following primary components:

- Review of initially screened site's historical flow and pressure information for hydro power production potential.
- Evaluation of the top candidate sites for in-conduit hydro generation economic feasibility.
- Develop high level assessment of project costs and expected revenue for potential sites.

2.0 Evaluation Methodology

From a list of 41 potential in-conduit energy recovery site locations in the SCVWD system, thirteen (13) were initially identified as having hydro power generating potential. The following evaluation was conducted as a high level assessment of the planning level costs and revenue potential for these thirteen (13) candidate sites. From the evaluation results, a determination of the feasibility of in-conduit hydro generation was made. The following information was reviewed as part of the evaluation:

- Flow and head data from August 1, 2010 to September 30, 2012 for each of the 41 sites, including a theoretical power output calculation.
- Aerial or street level photos for the prescreened 13 candidate sites.
- Selected as-built site drawings for six out of eight prescreened treated water candidate sites.

Turbine Selection

The evaluation process began with the analysis of each site's available flow and head conditions. This process included developing a Flow duration curve and a head exceedance curve for each site based on the data provided by SCVWD. Using this information, a turbine type was selected and the turbine's design parameters were established. For the purpose of this high level evaluation only, Francis, Kaplan or Pelton type turbines were considered as a base line for cost and production estimates. Final selection of the turbine type would need to be done during the detailed design phase for the candidate facilities.

Power Production Potential

Using the head and flow data and the selected turbine type and design parameters, the evaluation determined monthly and annual power generation at each site. Using this information, an average generation capacity and design capacity for the in-conduit facility was found and a plant capacity factor was determined. The average monthly energy values were then used to calculate the power generation income after an assumed hydro facility completion in 2014.

Power Pricing and Green Energy Incentives

To determine the power generation income, the evaluation model used the AURORA$^{xmp®}$ Electric Market Model to forecast market prices in the state of California. Prices were forecasted for the next twenty years and were projected to increase in real terms at a rate above inflation. For any year after the first twenty years, the price per kilowatt was held constant.

The evaluation also considered the financial incentives available for small hydro power generation. In California, Green Energy Incentives are performance-based through which Feed-in Tariff contracts can be signed in 10, 15 or 20 year increments. Upon signing these contracts, the Renewable Energy Credits (RECs) are surrendered for the life of the contract to the power utility. Also, in California federal renewable incentives cannot be combined with this performance-based incentive. For this evaluation, it is assumed that a 20 year contract has been signed, adding an additional $0.09840/kWh. Additional information about the Feed-in Tariff program in California can be found at the California Public Utility Commission (CPUC) web site http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/feedintariffs.htm.

Cost Calculations

The evaluation considered construction costs, other non-construction development costs, and various annual expenses that would be expected for operations. Construction costs included major equipment components, ancillary mechanical and electrical equipment, civil costs, transformers and transmission lines, sales tax, contingencies, and engineering and construction management costs. In many of the sites evaluated, a below ground facility was either required or considered and the associated additional costs of such a facility were applied.

Non-construction development costs included potential mitigation costs and in-conduit licensing exemption costs. The mitigation costs were applied depending on the specific site's conditions and constraints due to its location or surrounding environment.

Various annual expenses included variable and fixed operation and maintenance costs, interconnection fees, insurance, relevant taxes, overhead, and long term funding for maintenance.

Revenue, Costs and Net Present Value

The annual revenue determined in the evaluation was the power generation income minus the annual costs. For each site, a projected total cost (including the total construction cost and annual O&M costs) over a 50 year period and the projected revenue over a 50 year period was calculated to Net Present Value. The Net Present Value, shown in 2012 dollars, was calculated with an applied Federal Discount Rate of 2%. This rate was used because Federal planning studies require the use of the Federal discount rate for economic analysis, which is published annually by the Office of Management and Budget.

The last step of the evaluation included a ranking of the various sites based on the calculated NPV. A positive NPV savings number indicates that there is potential for the benefits of the site development to exceed the costs, therefore could potentially be financially viable.

Evaluation Conclusions

Each site's evaluation is concluded with an overall site summary of the physical and construction limitations and financial findings. Based on these findings, feasibility for each site's in-conduit hydro generation potential is determined. The criteria of feasibility included the following:

- If the evaluation found that a site had a positive Net Present Value savings both with and without Green Energy Incentives applied, the site was found to be feasible.
- If the evaluation found that a site had a negative Net Present Value of savings without Green Energy Incentives and a positive Net Present Value with Green Energy Incentives, the site was found to be feasible..
- If the evaluation found that a site had a negative Net Present Value of savings with and without Green Energy Incentives applied, the site was found to be not feasible for hydro generation.

3.0 Candidate Site Evaluations

3.1 TREATED WATER CANDIDATE SITE EVALUATIONS

The SCVWD treated water sites evaluated for in-conduit hydro generation potential were analyzed at several different downstream pressures. SCVWD staff indicated that there are no contractual obligations at the treated water sites and that B&V should determine the available head to the turbine by using a downstream pressure of 20 psi. Additionally, B&V performed site evaluations at downstream pressures of 40 psi and 80 psi for comparative purposes.

3.1.1 Hostetter Turnout

Site Description

Existing Structure: The Hostetter turnout is housed in a 13'x15'x11' foot concrete vault which contains a 20 inch butterfly valve and a flowmeter.

Space Availability: As seen in Figure 1, the location of the Hostetter turnout is in a neighborhood directly in front of existing residences on a busy street. A buried vault is the only available option for a potential hydro generation facility. Installation and construction access are sizable cost considerations for the preliminary development of a facility.

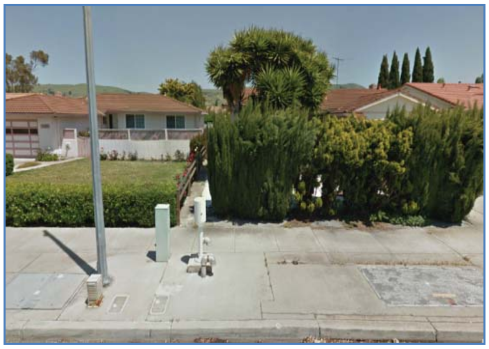

Figure 1 Photo of Hostetter Turnout Site

Flow Conditions: Figure 2 is the Flow Duration Curve for the Hostetter turnout. It shows that flows of greater than 5 cfs exist more than 90% of the time.

Evaluation

The Hostetter site was evaluated at three different downstream pressures to determine estimated planning level costs and projected revenue for a buried hydro generation facility. The results of this evaluation are summarized in Table 2.

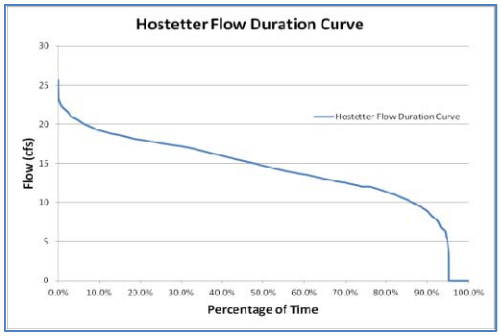

Figure 2 Hostetter Flow Duration Curve

Table 2 Hostetter Turnout Hydro Generation Evaluation Summary.

EVALUATION ITEM	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =80PSI
Hydro Generation Equipment			
Turbine Type	Francis	Francis	Francis
Available Head	165 – 317 (ft)	135 – 260 (ft)	75 – 144 (ft)
Turbine Design Head	254 (ft)	208 (ft)	116 (ft)
Flow Limits	5 – 23 (cfs)	5 – 23 (cfs)	5 – 23 (cfs)
Hydro Facility			
Installed Plant Capacity	420 kW	350 kW	200kW
Estimated Annual Production	2,150MWh	1,750MWh	950MWh
Plant Capacity Factor	0.60	0.60	0.59
Development Costs			
Total Construction Cost	$1,551,600	$1,423,100	$1,118,300
Annual O&M Cost	$69,500	$63,500	$50,300
Projected Total Cost Over 50 year Period	$3,474,000	$3,181,500	$2,510,700
Revenue			
Projected Total Revenue over 50 year Period (with Green Incentives)	$8,313,100	$6,771,100	$3,680,000
Projected Total Revenue over 50 year Period (without Green Incentives)	$4,917,900	$4,005,400	$2,176,100
Estimated NPV of Savings (with Green Incentives)	$4,839,100	$3,589,600	$1,169,300
Estimated NPV of Savings (without Green Incentives)	$1,443,900	$823,900	-$334,600

Conclusion

The Hostetter site has good available pressure head when the downstream pressure is 20 psi or 40 psi. When a downstream pressure of 80 psi is analyzed the available head to the turbine drops substantially. The flow conditions at the Hostetter site are consistent and show good duration. Due to the close proximity of existing residences and its busy street location, a potential hydro generation facility at Hostetter would have to be built in a buried vault. Additionally, design considerations would have to be taken to mitigate the noise of the turbine and a water cooling system would have to be added to the generator.

Considering the associated costs with the aforementioned design criteria, the required cooperation between existing utilities at the site and general installation constraints of a buried facility, the Hostetter site offers a positive NPV of savings at 20, 40 and 80 psi downstream pressure with Green Incentives. The facility offers a positive NPV at 20 and 40 psi downstream without Green Incentives. The only negative NPV is for the facility to operate at a downstream pressure of 80 psi without Green Incentives. Despite the drawbacks associated with a buried facility the Hostetter site is potentially feasible for hydro power generation.

3.2 Ocala Turnout

Site Description

Existing Structure: The Ocala turnout is a buried 10'x13' concrete vault that houses a pipe increase from 20 inches to 30 inches in diameter and a flowmeter.

Space Availability: As seen in Figure 3, the Ocala turnout is located near existing residences with access from White Road, the adjacent busy street. The site offers access for any potential construction but would require traffic control for the installation of the buried facility.

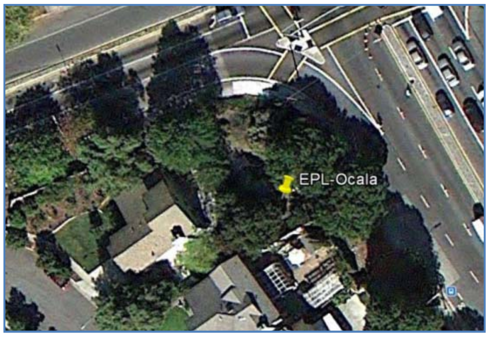

Figure 3 Aerial Photo of Ocala Turnout Site

Flow Conditions: Figure 4 is the Flow Duration Curve for the Ocala turnout. It shows that flows are consistently above 5 cfs for 87% of the time.

Evaluation

The Ocala site was evaluated at three different downstream pressures and as an above ground facility and a buried facility. This evaluation determined estimated planning level costs and projected revenue for all six possible outcomes. The results of this evaluation are summarized in Table 3.

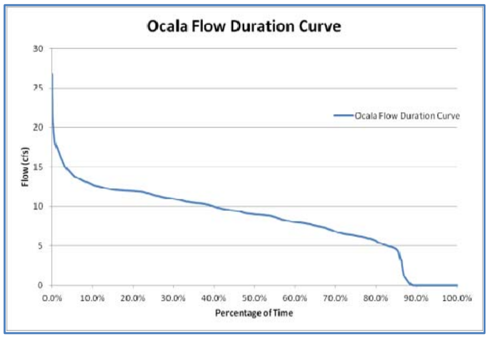

Figure 4 Ocala Flow Duration Curve

Table 3 Ocala Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =40PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =80PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =80PSI
Hydro Generation Equipment						
Turbine Type	Francis	Francis	Francis	Francis	Francis	Francis
Available Head	157-302(ft)	127-244(ft)	67 – 129(ft)	157-302(ft)	127-244(ft)	67 – 129(ft)
Turbine Design Head	242 (ft)	196 (ft)	103 (ft)	242 (ft)	196 (ft)	103 (ft)
Flow Limits	5 - 11 (cfs)	5 - 11 (cfs)	5 - 11 (cfs)	5 - 11 (cfs)	5 - 11 (cfs)	5 - 11 (cfs)
Hydro Facility						
Installed Plant Capacity	190kW	160kW	80kW	190kW	160kW	80kW
Estimated Annual	1,190MWh	950MWh	500MWh	1,190MWh	950MWh	500MWh

EVALUATION ITEM	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =40PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =80PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =80PSI
Production						
Plant Capacity Factor	0.72	0.72	0.70	0.72	0.72	0.70
Development Costs						
Total Construction Cost	$807,100	$741,700	$588,000	$972,800	$892,700	$700,400
Annual O&M Cost	$48,000	$44,600	$36,700	$48,000	$44,600	$36,700
Projected Total Cost Over 50 year Period	$2,147,100	$1,986,000	$1,613,100	$2,306,000	$2,130,300	$1,721,200
Revenue						
Projected Total Revenue over 50 year Period (with Green Incentives)	$4,571,000	$3,684,600	$1,910,000	$4,571,000	$3,684,600	$1,910,000
Projected Total Revenue over 50 year Period (without Green Incentives)	$2,700,000	$2,176,200	$1,128,300	$2,700,000	$2,176,200	$1,128,300
Estimated NPV of Savings (with Green Incentives)	$2,423,900	$1,698,600	$296,900	2265000	$1,554,300	$188,800
Estimated NPV of Savings (without Green Incentives)	$552,900	$190,200	-$484,800	394000	$45,900	-$592,900

Conclusion

The Ocala turnout is located near existing residences and would have some additional design considerations for the installation of a hydro generation facility. The site could be accessed from White Road during construction but would require traffic control and coordination with existing utilities. The available head and flow conditions are consistent enough to produce a positive NPV whether or not Green Energy Incentives are applied when there is a downstream pressure of 20 or 40 psi. When the downstream pressure is increased to 80 psi an in-conduit hydro generation facility only becomes feasible with Green Energy Incentives considered. The Ocala site is not feasible for hydro generation if the downstream pressure is 80 psi without Green Energy incentives.

4.3.3 Alum Rock Turnout

Site Description

Existing Structure: The Alum Rock turnout is a 10’x10’ foot buried concrete vault housing a 24 inch butterfly valve installed just before a pipe reduction from 24 inches to 18 inches.

Space Availability: As seen in Figure 5, the Alum Rock turnout is on the corner of a parking lot with the corner’s adjacent sides North White Road and Alum Rock Avenue. The site offers easy access for any potential construction but would require traffic control for either an above ground or buried facility during construction.

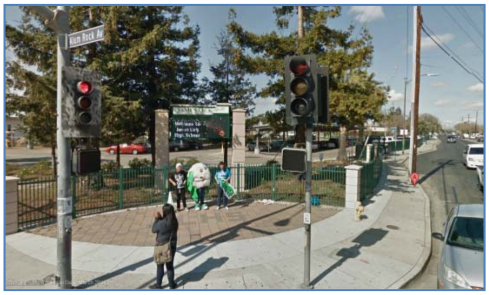

Figure 5 Photo of Alum Rock Turnout

Flow Conditions: Figure 6 is the Flow Duration Curve for the Alum Rock turnout. It shows flows between 5 cfs and 18 cfs are present for more than 92% of the time.

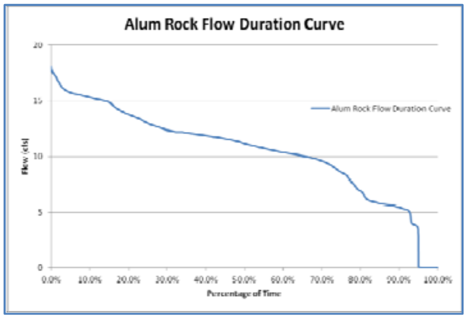

Figure 6 Alum Rock Flow Duration Curve

Evaluation

The Alum Rock site was evaluated at three different downstream pressures and as an above ground facility and a buried facility. This evaluation determined estimated planning level costs and projected revenue for all six possible outcomes. The results of this evaluation are summarized in Table 4.

Table 4 Alum Rock Turnout Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =40PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =80PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =80PSI
Hydro Generation Equipment						
Turbine Type	Francis	Francis	Francis	Francis	Francis	Francis
Available Head	147-284(ft)	117-226(ft)	57 – 110(ft)	147-284(ft)	117-226(ft)	57 – 110(ft)
Turbine Design Head	227 (ft)	181 (ft)	88 (ft)	227 (ft)	181 (ft)	88 (ft)
Flow Limits	5 - 18 (cfs)	5 - 18 (cfs)	5 - 18 (cfs)	5 - 18 (cfs)	5 - 18 (cfs)	5 - 18 (cfs)
Hydro Facility						
Installed Plant Capacity	300kW	240 kW	120 kW	300kW	240 kW	120 kW
Estimated Annual	1,460MWh	1,160MWh	560MWh	1,460MWh	1,160MWh	560MWh

EVALUATION ITEM	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =40PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =80PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =80PSI
Production						
Plant Capacity Factor	0.57	0.57	0.56	0.57	0.57	0.56
Development Costs						
Total Construction Cost	$1,046,800	$954,000	$717,700	$1,270,300	$1,155,000	$861,600
Annual O&M Cost	$58,500	$53,400	$41,500	$58,500	$53,400	$41,500
Projected Total Cost Over 50 year Period	$2,675,000	$2,440,000	$1,873,400	$2,890,000	$2,633,000	$2,011,800
Revenue						
Projected Total Revenue over 50 year Period (with Green Incentives)	$5,639,000	$4,480,700	$2,160,000	$5,639,000	$4,480,700	$2,160,000
Projected Total Revenue over 50 year Period (without Green Incentives)	$3,331,500	$2,647,200	$1,276,200	$3,331,500	$2,647,200	$1,276,200
Estimated NPV of Savings (with Green Incentives)	$2,964,000	$2,040,700	$286,600	$2,749,000	$1,847,700	$148,200
Estimated NPV of Savings (without Green Incentives)	$656,500	$207,200	-$597,200	$441,500	$14,200	-$735,600

Conclusion

The Alum Rock turnout has a consistent flow pattern with a good head pressure when evaluated at downstream pressures of 20 psi or 40 psi. The head associated with a downstream pressure of 80 psi is substantially less. The location offers easy access, plenty of space and requires no additional cost considerations for construction installation constraints if the facility is built above ground. If the facility is built below ground, in a buried vault, additional cooperation between existing utilities at the site and traffic control of North White Road and Alum Rock Avenue would be required. The difference between the installation of an above ground facility and a buried facility is the additional construction installation costs.

The available head and flow conditions are consistent enough to produce a positive NPV whether or not Green Energy Incentives are applied when there is a downstream pressure of 20 or 40 psi. When the downstream pressure is increased to 80 psi an in-conduit hydro generation facility only becomes feasible with Green Energy Incentives considered. The Alum Rock site is not feasible for hydro generation if the downstream pressure is 80 psi without Green Energy incentives.

4.3.4 Pinos Turnout

Site Description

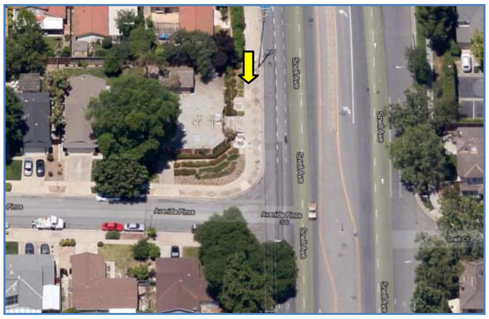

Figure 7 Aerial Photo of Pinos Turnout Site

Existing Structure: The Pinos turnout is a buried concrete vault only large enough to house an 18 inch butterfly valve controlling the same diameter pipe. The pipe is a line that is an off-shoot from the 72 inch Snell mainline.

Space Availability: As seen in Figure 7, the Pinos turnout is located on the corner of Avenida Pinos and Snell Avenue. There is an open lot surrounded by a wooden fence. Space for an above ground facility is available however there are existing residences next to the lot which may dictate using a buried vault. Access and space for any potential hydro facility would not require extensive considerations.

Flow Conditions: Figure 8 is the Flow Duration Curve for the Pinos turnout. It shows that flows are consistently between 5 and 15 cfs for 88% of the time.

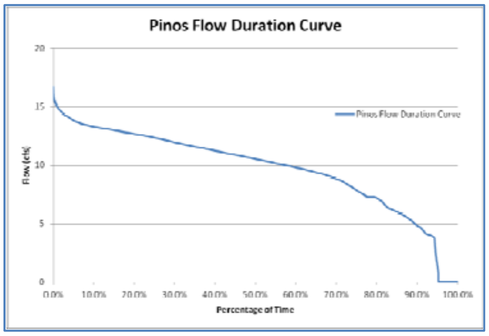

Figure 8 Pinos Flow Duration Curve

Evaluation

The Pinos site was evaluated at three different downstream pressures and as an above ground facility and a buried facility. This evaluation determined estimated planning level costs and projected revenue for all six possible outcomes. The results of this evaluation are summarized in Table 5.

Table 5 Pinos Turnout Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =40PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =80PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =80PSI
Hydro Generation Equipment						
Turbine Type	Francis	Francis	Francis	Francis	Francis	Francis
Available Head	139-267(ft)	109-209(ft)	49 – 94 (ft)	139-267(ft)	109-209(ft)	49 – 94 (ft)
Turbine Design Head	214 (ft)	168 (ft)	76 (ft)	214 (ft)	168 (ft)	76 (ft)
Flow Limits	5 - 15 (cfs)	5 - 15 (cfs)	5 - 15 (cfs)	5 - 15 (cfs)	5 - 15 (cfs)	5 - 15 (cfs)
Hydro Facility						
Installed Plant Capacity	230kW	180 kW	80 kW	230kW	180kW	80kW
Estimated Annual Production	1280MWh	1000MWh	440MWh	1280MWh	1000MWh	440MWh
Plant Capacity Factor	0.65	0.65	0.63	0.65	0.65	0.63
Development Costs						
Total Construction Cost	$918,400	$833,900	$607,700	$1,110,900	$1,006,000	$724,900
Annual O&M Cost	$52,500	$48,000	$37,000	$52,500	$48,000	$37,000
Projected Total Cost Over 50 year Period	$2,381,200	$2,170,000	$1,642,500	$2,566,300	$2,335,300	$1,755,200
Revenue						
Projected Total Revenue over 50 year Period (with Green Incentives)	$4,939,700	$3,862,200	$1,687,800	$4,939,700	$3,862,200	$1,687,800
Projected Total Revenue over 50 year Period (without Green Incentives)	$2,926,000	$2,287,800	$1,000,100	$2,926,000	$2,287,800	$1,000,100
Estimated NPV of Savings (with Green Incentives)	$2,558,500	$1,692,200	$45,300	$2,373,400	$1,526,900	-$67,400
Estimated NPV of Savings (without Green Incentives)	$544,800	$117,800	$642,400	$359,700	-$47,500	-755,100

Conclusion

The Pinos site has flow with great consistency and duration. The site has access for construction but may offer some constraints due to its close proximity to existing residences. If an above ground facility was built noise mitigation would definitely have to be a design consideration. If a buried facility was installed a cooling water system would also have to be designed.

All the potential hydro generation facilities considered in this evaluation showed a positive NPV of savings except for hydro generation facilities operating at 80 psi downstream pressure with or without Green Energy Incentives and buried vault facility operating at 40 psi downstream pressure without Green Energy incentives.

4.3.5 Skyway Turnout

Site Description

Existing Structure: The Skyway turnout is a buried concrete vault only large enough to house an 18 inch butterfly valve controlling the same diameter pipe. The pipe is a line that is an off-shoot from the 60 inch Snell mainline.

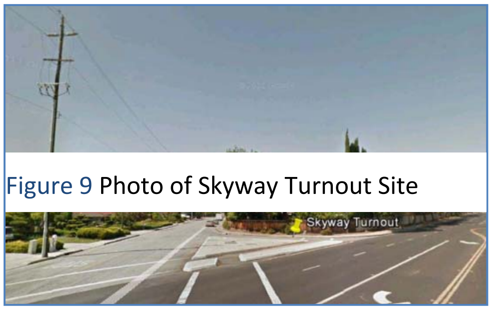
Figure 9 Photo of Skyway Turnout Site

Space Availability: As seen in Figure 9, the Skyway turnout is located under a traffic island on the corner of Pinon Place and Skyway Drive. The site offers easy access for any potential construction but would require traffic control for the installation of the buried facility, which would be required at the site.

Flow Conditions: Figure 10 is the Flow Duration Curve for the Skyway turnout. It shows that flows are consistently between 10 and 15 cfs for 68% of the time and greater than 5 cfs more than 80% of the time.

Evaluation

The Skyway site was evaluated at three different downstream pressures to determine estimated planning level costs and projected revenue for a buried hydro generation facility. The results of this evaluation are summarized in Table 6.

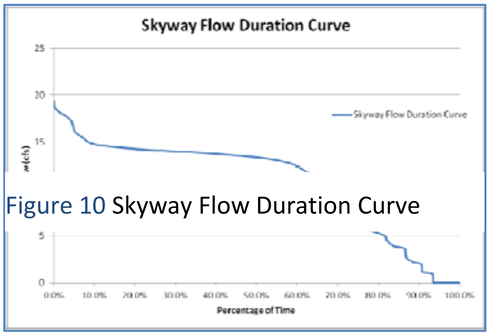
Figure 10 Skyway Flow Duration Curve

Table 6 Skyway Hydro Generation Evaluation Summary.

EVALUATION ITEM	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =80PSI
Hydro Generation Equipment			
Turbine Type	Francis	Francis	Francis
Available Head	139 – 267 (ft)	109 – 209 (ft)	49 – 93 (ft)
Turbine Design Head	213 (ft)	167 (ft)	75 (ft)
Flow Limits	5 – 15 (cfs)	5 – 15 (cfs)	5 – 15 (cfs)
Hydro Facility			
Installed Plant Capacity	230kW	180kW	80kW
Estimated Annual Production	1,340MWh	1,000MWh	440MWh
Plant Capacity Factor	0.69	0.68	0.65
Development Costs			
Total Construction Cost	$1,109,000	$1,004,000	$721,300
Annual O&M Cost	$52,400	$47,900	$37,000
Projected Total Cost Over 50 year Period	$2,562,300	$2,331,000	$1,748,300
Revenue			

EVALUATION ITEM	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWNSTREAM PRESSURE =80PSI
Projected Total Revenue over 50 year Period (with Green Incentives)	$5,198,600	$4,050,500	$1,716,700
Projected Total Revenue over 50 year Period (without Green Incentives)	$3,085,500	$2,404,200	$1,020,000
Estimated NPV of Savings (with Green Incentives)	$2,636,300	$1,719,500	-$31,600
Estimated NPV of Savings (without Green Incentives)	$523,200	$73,200	-$728,300

Conclusion

The Skyway turnout site offers easy access for any potential construction of an in-conduit hydro generation facility but will require traffic control and existing utility line coordination during the excavation and installation phase. The Skyway site is far enough away from existing residences that no extenuating considerations for sound mitigation would be required but the generator would most likely require the addition of a cooling water system. The evaluation found that even with the additional installation costs of installing a buried facility at the Skyway site hydro generation is potentially feasible with downstream pressures of 20 psi and 40 psi. The Skyway site is not feasible for hydro generation at a downstream pressure of 80 psi.

4.3.6 Santa Clara Turnout

Site Description

Existing Structure: The Santa Clara turnout is a buried 13' foot concrete vault that houses a 12 inch butterfly valve and flowmeter.

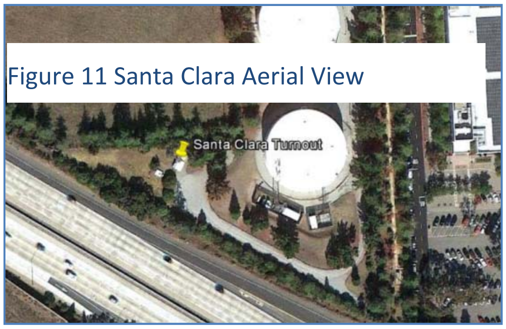
Figure 11 Santa Clara Aerial View

Space Availability: As seen in Figure 11, the Santa Clara turnout is located on the north side of highway 280, behind the Agilent Technologies Campus. The site offers access and space for the potential construction of a hydro generation facility.

Flow Conditions: Figure 12 is the Flow Duration Curve for the Santa Clara turnout. It shows that flows are consistently between 5 and 10 cfs for 92% of the time.

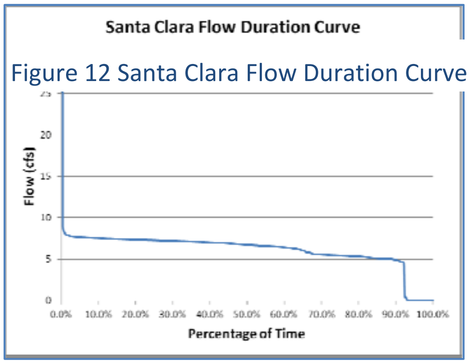
Figure 12 Santa Clara Flow Duration Curve

Evaluation

The Santa Clara site was evaluated at three different downstream pressures to determine estimated planning level costs and projected revenue for an above ground hydro generation facility. The results of this evaluation are summarized in Table 7.

Table 7 Santa Clara Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY DOWNSTREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWNSTREAM PRESSURE =40PSI	ABOVE GROUND FACILITY DOWNSTREAM PRESSURE =80PSI
Hydro Generation Equipment			
Turbine Type	Francis	Francis	Francis
Available Head	146 – 280(ft)	116 – 223 (ft)	56 – 107 (ft)
Turbine Design Head	224 (ft)	178 (ft)	86 (ft)
Flow Limits	5 – 8 (cfs)	5 – 8 (cfs)	5 – 8 (cfs)
Hydro Facility			
Installed Plant Capacity	130kW	100kW	50kW
Estimated Annual Production	820MWh	640MWh	250MWh
Plant Capacity Factor	0.76	0.75	0.62
Development Costs			
Total Construction Cost	$657,300	$603,400	$465,000
Annual O&M Cost	$41,300	$38,500	$31,900
Projected Total Cost Over 50 year Period	$1,810,400	$1,678,300	$1,357,600
Revenue			
Projected Total Revenue over 50 year Period (with Green Incentives)	$3,149,200	$2,467,300	$983,400
Projected Total Revenue over 50 year Period (without Green Incentives)	$1,859,400	$1,456,700	$580,400
Estimated NPV of Savings (with Green Incentives)	$1,338,800	$789,000	-$374,200
Estimated NPV of Savings (without Green Incentives)	$49,000	-$221,600	-$777,200

Conclusion

The Santa Clara site has enough open space and would have few problems with access if a hydro generation facility were to be constructed. The site also has enough available pressure head range for use by the turbine. The only problem with the Santa Clara site is the available flow, which is very low most of the time. However, as long as the turbine is designed to accommodate this condition the Santa Clara site shows positive NPV of savings for downstream pressures of 20 or 40 psi with green Energy incentives.

When the site is evaluated at 80 psi downstream pressure the available head coupled with the low flow does not allow enough power generation and the NPV of savings is negative. If the downstream pressure is 40 psi the Santa Clara site is potentially feasible for hydro power generation Green Energy incentives. When the downstream pressure is to 40 psi the NPV of savings is negative without Green Energy Incentives and the site is not feasible for hydro generation.

4.3.7 Cox Turnout

Site Description

Existing Structure: No information about the Cox turnout site's existing conditions was provided by SCVWD.

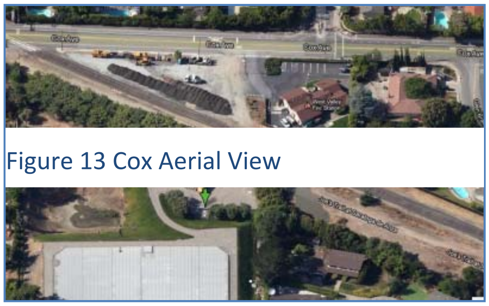

Figure 13 Cox Aerial View

Space Availability: As seen in Figure 13, the Cox turnout is located off of Cox Avenue just south of a nearby railroad. From the aerial photo the site appears to offer access and space for the potential construction of a hydro generation facility.

Flow Conditions: Figure 14 is the Flow Duration Curve for the Cox turnout. It shows that flows fluctuate but are above 10 cfs 75% of the time and at least 5 cfs 90% of the time.

Evaluation

Due to the limited information provided by SCVWD, the Cox site was evaluated at two different downstream pressures and as an above ground facility and a buried facility. This evaluation determined estimated planning level costs and projected revenue for all four possible outcomes. The results of this evaluation are summarized in Table 8.

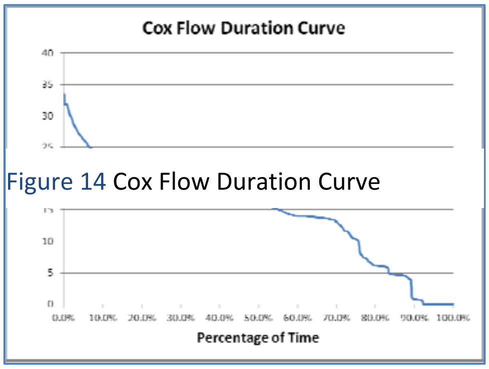

Figure 14 Cox Flow Duration Curve

Table 8 Cox Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =40PSI
Hydro Generation Equipment				
Turbine Type	Francis	Francis	Francis	Francis
Available Head	47-90(ft)	17-32(ft)	47-90(ft)	17-32(ft)
Turbine Design Head	72 (ft)	25 (ft)	72 (ft)	25 (ft)
Flow Limits	5 - 18 (cfs)	5 - 18 (cfs)	5 - 18 (cfs)	5 - 18 (cfs)
Hydro Facility				
Installed Plant Capacity	90kW	30kW	90kW	30kW
Estimated Annual Production	430MWh	150MWh	430MWh	150MWh
Plant Capacity Factor	0.56	0.55	0.56	0.55
Development Costs				
Total Construction Cost	$654,500	$413,300	$783,000	$483,300
Annual O&M Cost	$38,800	$29,500	$38,800	$29,500

EVALUATION ITEM	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =40PSI
Projected Total Cost Over 50 year Period	$1,735,600	$1,240,000	$1,859,200	$1,307,400
Revenue				
Projected Total Revenue over 50 year Period (with Green Incentives)	$1,663,300	$573,300	$1,663,300	$573,300
Projected Total Revenue over 50 year Period (without Green Incentives)	$982,800	$338,700	$982,800	$338,700
Estimated NPV of Savings (with Green Incentives)	-$72,300	-$666,700	-$195,900	-$734,100
Estimated NPV of Savings (without Green Incentives)	-$752,800	-$901,300	-$876,400	-$968,700

Conclusion

The Cox site appears to have space and access if a hydro generation facility were to be constructed. However, the problem with the site is the available head for use by the turbine. Under any scenario evaluated the Cox facility does not generate a positive NPV of savings is not feasible for in-conduit energy recovery.

4.3.8 Congress Turnout

Site Description

Existing Structure: No information about the Congress turnout site's existing conditions was provided by SCVWD.

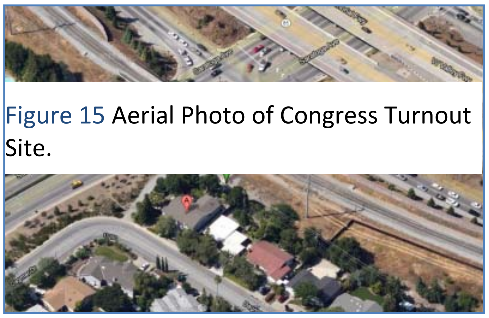

Figure 15 Aerial Photo of Congress Turnout Site.

Space Availability: As seen in Figure 15, the Congress turnout is located off of Saratoga Avenue behind an existing residence. From the aerial photo the site appears to offer access but may have additional construction constraints due to its close proximity to an existing residence.

Flow Conditions: Figure 16 is the Flow Duration Curve for the Congress turnout. It shows that there is only some sort of flow at the site 64% of the time and flows greater than 5 cfs 60% of the time.

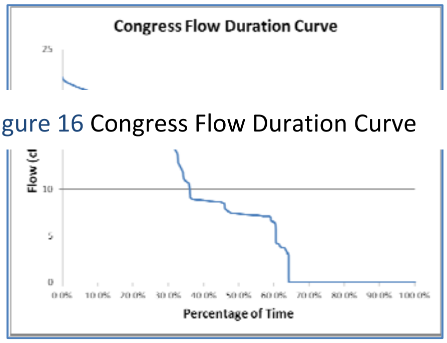

Figure 16 Congress Flow Duration Curve

Evaluation

Due to the limited information provided by SCVWD, the Congress site was evaluated at two different downstream pressures and as an above ground facility and a buried facility. This evaluation determined estimated planning level costs and projected revenue for all four possible outcomes. The results of this evaluation are summarized in Table 9.

Table 9 Congress Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =20PSI	ABOVE GROUND FACILITY DOWN-STREAM PRESSURE =40PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =20PSI	BURIED VAULT FACILITY DOWN-STREAM PRESSURE =40PSI
Hydro Generation Equipment				
Turbine Type	Francis	Francis	Francis	Francis
Available Head	50-95(ft)	19-37(ft)	50-95(ft)	19-37(ft)
Turbine Design Head	76 (ft)	30 (ft)	76 (ft)	30 (ft)
Flow Limits	5 - 15 (cfs)	5 - 15 (cfs)	5 - 15 (cfs)	5 - 15 (cfs)
Hydro Facility				
Installed Plant Capacity	80kW	30kW	80kW	30kW
Estimated Annual Production	320MWh	120MWh	320MWh	120MWh
Plant Capacity Factor	0.47	0.46	0.47	0.46
Development Costs				
Total Construction Cost	$609,200	$407,000	$726,700	$475,500
Annual O&M Cost	$37,100	$29,300	$37,100	$29,300
Projected Total Cost Over 50 year Period	$1,645,700	$1,228,700	$1,758,700	$1,294,600
Revenue				
Projected Total Revenue over 50 year Period (with Green Incentives)	$1,225,800	$466,000	$1,225,800	$466,000
Projected Total Revenue over 50 year Period (without Green Incentives)	$726,700	$276,300	$726,700	$276,300
Estimated NPV of Savings (with Green Incentives)	-$419,900	-$762,700	-$532,900	-$828,600
Estimated NPV of Savings (without Green Incentives)	-$919,000	-$952,400	-$1,032,000	-$1,018,300

Conclusion

The Congress site has several problems for the installation of an in-conduit hydro generation facility. Due to its close proximity to existing residences additional costs would be encountered in either mitigating noise or the potential requirement of having the facility buried. Also, the inconsistent flow coupled with the low head associated with a downstream pressure of 20 psi or 40 psi makes the annual power production small. These factors make the Congress site not feasible for hydro generation in any situation.

4.4 RAW WATER CANDIDATE SITE EVALUATIONS

4.4.1 Half Road and Madrone Turnout

Site Description

Space Availability: As seen in Figure 17, the Half Road and Madrone turnout is on the outer edge of an orchard right off of Half Road. There is abundant space available and easy access for any potential construction.

Flow Conditions: Figure 18 is the Flow Duration Curve for the Half Road and Madrone turnout. It shows that flows of greater than 10 cfs exist more than 75% of the time and flows of 5 cfs more than 88% of the time.

Evaluation

The Half Road and Madrone turnout site was evaluated to determine estimated planning level costs and projected revenue for an above ground hydro generation facility. The results of this evaluation are summarized in Table 10.

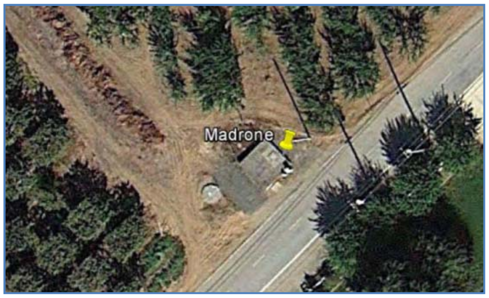

Figure 17 Aerial Photo of Half Road and Madrone Turnout Site

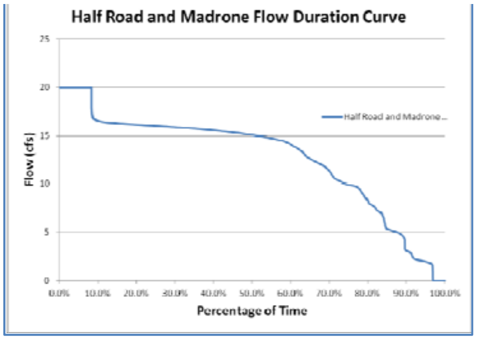

Figure 18 Half Road and Madrone Flow Duration Curve

Table 10 Half Road and Madrone Turnout Hydro Generation Evaluation.

EVALUATION ITEM	ABOVE GROUND FACILITY
Hydro Generation Equipment	
Turbine Type	Francis
Available Head	111 – 214(ft)
Turbine Design Head	171 (ft)
Flow Limits	5 – 16 (cfs)
Hydro Facility	
Installed Plant Capacity	200kW
Estimated Annual Production	940MWh
Plant Capacity Factor	0.56
Development Costs	
Total Construction Cost	$871,300
Annual O&M Cost	$49,600
Projected Total Cost Over 50 year Period	$2,252,900
Revenue	
Projected Total Revenue over 50 year Period (with Green Incentives)	$3,646,500
Projected Total Revenue over 50 year Period (without Green Incentives)	$2,164,200
Estimated NPV of Savings (with Green Incentives)	$1,393,600
Estimated NPV of Savings (without Green Incentives)	-$88,700

Conclusion

The Half Road and Madrone turnout site has available surrounding land and easy access for the potential construction of a hydro generation facility. The site offers consistent flow and head patterns which could produce 940 MWh annually. Due to the available head and flow and the ability to construct a facility above ground the Half Road and Madrone turnout is feasible for in-conduit hydro generation. The projected revenue over a 50 year period would produce $2.2 million dollars with an NPV of savings of $1.4 million dollars with Green Energy Incentives applied. The facility would have a negative NPV of savings without Green Energy Incentives.

4.4.2 Uvas Reservoir Outlet

Site Description

Space Availability: As seen in Figure 19, the Uvas Reservoir outlet is surrounded by open area with abundant space available and easy access for any potential construction.

Flow Conditions: Figure 20 is the Flow Duration Curve for the Uvas Reservoir outlet. It shows that flows of greater than 5 cfs exist more than 95% of the time.

Evaluation

The Uvas Reservoir outlet site was evaluated to determine estimated planning level costs and projected revenue for an above ground hydro generation facility. The results of this evaluation are summarized in Table 11.

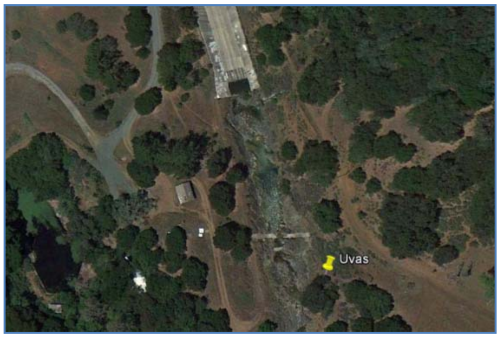

Figure 19 Aerial Photo of the Uvas Reservoir Outlet Site.

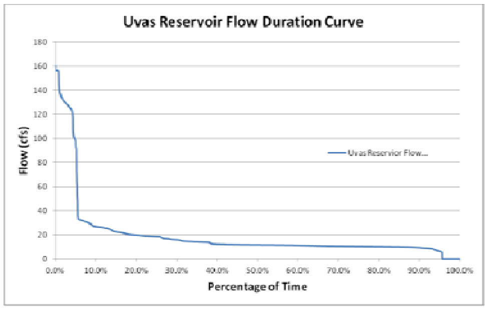

Figure 20 Uvas Reservoir Flow Duration Curve.

Table 11 Uvas Reservoir Outlet Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY
Hydro Generation Equipment	
Turbine Type	Francis
Available Head	55 – 107(ft)
Turbine Design Head	85 (ft)
Flow Limits	5 – 20 (cfs)
Hydro Facility	
Installed Plant Capacity	120kW
Estimated Annual Production	630MWh

EVALUATION ITEM	ABOVE GROUND FACILITY
Plant Capacity Factor	0.59
Development Costs	
Total Construction Cost	$749,400
Annual O&M Cost	$42,600
Projected Total Cost Over 50 year Period	$1,936,900
Revenue	
Projected Total Revenue over 50 year Period (with Green Incentives)	$2,415,600
Projected Total Revenue over 50 year Period (without Green Incentives)	$1,423,200
Estimated NPV of Savings (with Green Incentives)	$478,700
Estimated NPV of Savings (without Green Incentives)	-$513,700

Conclusion

The Uvas Reservoir outlet is in a remote and open area and would provide no constraints for the installation of a hydro generation facility. The flow is within the capabilities of a Francis type turbine 80% of the time. Another 10% of the time the turbine could operate in conjunction with a bypass piping network to accommodate the large flows that occasionally exist at the Uvas Reservoir outlet. Additionally a turbine designed and built by Ossberger could be used to accommodate the full range of head and flow conditions at the Uvas site. However, the costs considerations between a Francis type turbine and Ossberger type turbine would have to be considered and for the 10% of the time that the flow is outside the Francis type turbine's flow capacity, the Ossberger turbine's relevancy would need a more in-depth evaluation to justify its application.

The projected revenue over a 50 year period would produce $2.4 million dollars with an NPV of savings of $478,700 with Green Energy incentives applied. If Green Energy incentives were not accounted for with the Francis type turbine setup the NPV would be negative. As such, the Uvas Reservoir outlet site is feasible for in-conduit hydro generation only when Green Energy incentives are considered.

4.4.3 Vasona 805 Valve

Site Description

Space Availability: As seen in Figure 21, the Vasona 805 valve is located near the Vasona Pumping station. There is space available and access for any potential construction.

Flow Conditions: Figure 22 is the Flow Duration Curve for the Vasona 805 valve. It shows that flows of between 50 and 100 cfs are consistently present, with flows greater than 40 cfs more than 80% percent of the time.

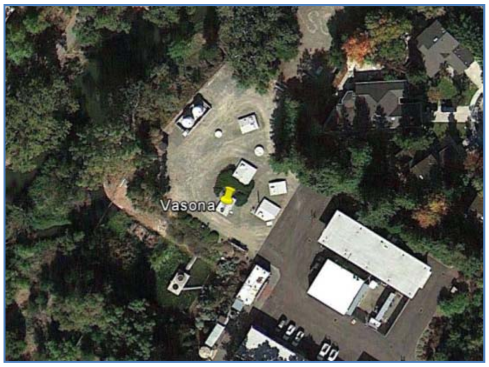

Figure 21 Vasona Aerial View

Evaluation

The Vasona 805 valve site was evaluated to determine estimated planning level costs and projected revenue for an above ground hydro generation facility. The model was performed with two different potential equipment setups because of the head and flow conditions. The first was based on a hydro generation facility that would use a Francis type turbine and the second was based on a hydro generation facility that would use a Kaplan type turbine.

The results of this evaluation are summarized in Table 12.

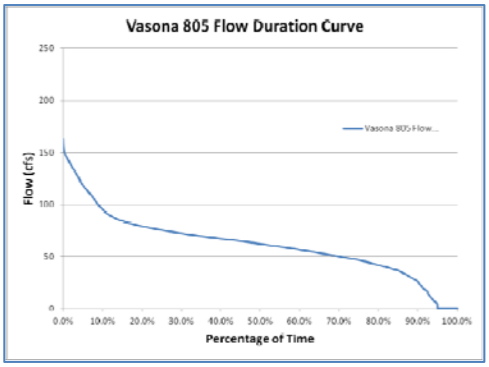

Figure 22 Vasona 805 Valve Flow Duration Curve

Table 12 Vasona 805 Valve Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY: FRANCIS TYPE TURBINE	ABOVE GROUND FACILITY: KAPLAN TYPE TURBINE
Hydro Generation Equipment		
Turbine Type	Francis	Kaplan
Available Head	28 – 54(ft)	28 – 54(ft)
Turbine Design Head	43 (ft)	43 (ft)
Flow Limits	14 – 71(cfs)	30 – 150(cfs)
Hydro Facility		
Installed Plant Capacity	220kW	460kW
Estimated Annual Production	840MWh	900MWh
Plant Capacity Factor	0.45	0.23
Development Costs		
Total Construction Cost	$1,120,300	$2,058,800
Annual O&M Cost	$55,600	$86,400
Projected Total Cost Over 50 year Period	$2,665,100	$4,443,500
Revenue		
Projected Total Revenue over 50 year Period (with Green Incentives)	$3,214,100	$3,457,400
Projected Total Revenue over 50 year Period (without Green Incentives)	$1,895,900	$2,040,400
Estimated NPV of Savings (with Green Incentives)	$549,000	-$986,100
Estimated NPV of Savings (without Green Incentives)	-$769,200	-$2,403,100

Conclusion

The Vasona 805 valve site has enough land on which a hydro generation facility could be built without construction installation constraints. The Vasona site also offers consistently high flow conditions which are suitable for hydro power generation. However, the low head of less than 55 feet is a drawback for the site. Due to these head and flow conditions two different evaluations were performed. The first used a Francis type turbine which operated in a range that could not handle all of the potential flow available at the site and would have to share the total available flow with a bypass pipe system. This would mean that the theoretical power potential of the Vasona site could not be realized but the less expensive Francis type turbine setup would offset this loss and offer an estimated NPV of savings of $549,000 if Green Energy incentives are applied. If Green Energy incentives were not accounted for with this turbine setup the NPV of savings would be negative.

The second approach would employ the use of a Kaplan type turbine which could accept all of the available flow at the site. However, because Kaplan type turbines are more expensive to purchase and maintain the estimated NPV, even with Green Energy incentives considered, would be negative. Overall, the Vasona site is feasible for in-conduit hydro generation only if a Francis type turbine was used and Green Energy incentives were considered.

4.4.4 Calero Modulation Valve

Site Description

Space Availability: As seen in Figure 23, the Calero modulation valve site is in an open area with no existing neighborhoods nearby. There is abundant space available and easy access for any potential construction.

Flow Conditions: Figure 24 is the Flow Duration Curve for the Calero modulation valve. It shows that flows of greater than 100 cfs exist more than 75% of the time and flows of 50 cfs more than 90% of the time.

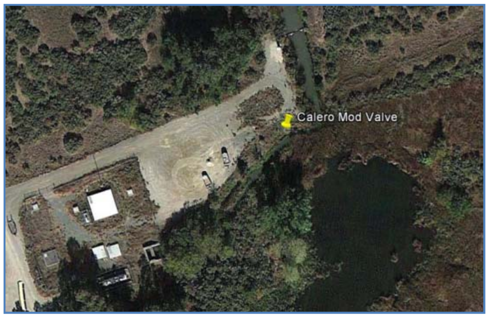

Figure 23 Aerial Photo of Calero Modulation Valve Site

Evaluation

The Calero modulation valve site was evaluated to determine estimated planning level costs and projected revenue for an above ground hydro generation facility. The results of this evaluation are summarized in Table 13.

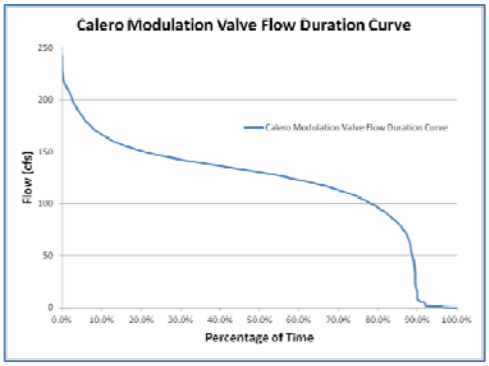

Figure 24 Calero Modulation Valve Flow Duration Curve

Table 13 Calero Modulation Valve Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY
Hydro Generation Equipment	
Turbine Type	Kaplan
Available Head	12 – 23(ft)
Turbine Design Head	18 (ft)
Flow Limits	36 – 180 (cfs)
Hydro Facility	
Installed Plant Capacity	240kW
Estimated Annual Production	690MWh
Plant Capacity Factor	0.35
Development Costs	
Total Construction Cost	$1,360,600
Annual O&M Cost	$61,100
Projected Total Cost Over 50 year Period	$3,050,900
Revenue	
Projected Total Revenue over 50 year Period (with Green Incentives)	$2,685,000
Projected Total Revenue over 50 year Period (without Green Incentives)	$1,601,900
Estimated NPV of Savings (with Green Incentives)	-$365,900
Estimated NPV of Savings (without Green Incentives)	-$1,449,000

Conclusion

The Calero site is wide open and would have no issues with constructing a hydro generation facility. The site also has large volume flows most of the time. The only problem with the Calero site is the available head, which is very low. Due to this condition the only available standard turbine option is a Kaplan type unit which is one of the most expensive turbines to install and to operate. These cost factors are reflected in the results of the evaluation with the high annual operations and maintenance cost of $61,100 for only 690 MW-hrs of annual energy production. Despite having a high theoretical power potential based on the high flow condition, the Calero site's estimated NPV of savings is negative even with Green Energy incentives and is not feasible for in-conduit hydro generation.

4.4.5 Peet Road Valve

Site Description

Space Availability: As seen in Figure 25, the Peet Road valve site is located within the Coyote Pumping Station with the surrounding area open and with easy access for any potential construction.

Flow Conditions: Figure 26 is the Flow Duration Curve for the Peet Road valve. It shows that flows are greater than 50 cfs 90% of the time.

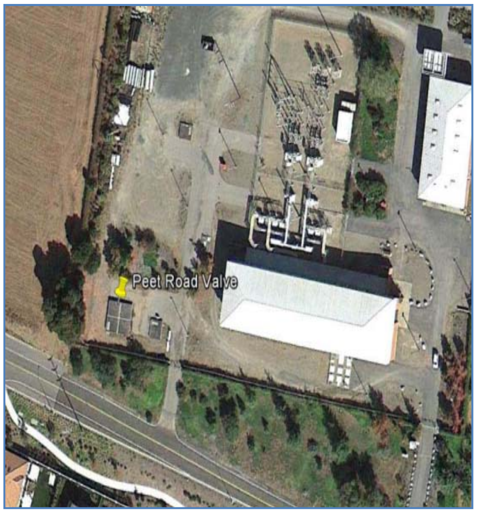

Figure 25 Aerial Photo of Peet Road Valve Site

Evaluation

The Peet Road valve site was evaluated to determine estimated planning level costs and projected revenue for an above ground hydro generation facility. The results of this evaluation are summarized in Table 14.

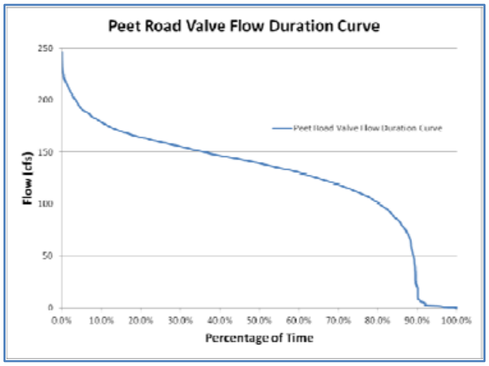

Figure 26 Peet Road Valve Flow Duration Curve

Table 14 Peet Road Valve Hydro Generation Evaluation Summary.

EVALUATION ITEM	ABOVE GROUND FACILITY
Hydro Generation Equipment	
Turbine Type	Kaplan
Available Head	9 – 18(ft)
Turbine Design Head	14 (ft)
Flow Limits	31 – 155 (cfs)
Hydro Facility	
Installed Plant Capacity	160kW
Estimated Annual Production	280MWh
Plant Capacity Factor	0.22
Development Costs	
Total Construction Cost	$1,056,200
Annual O&M Cost	$50,500
Projected Total Cost Over 50 year Period	$2,457,000

Revenue	
Projected Total Revenue over 50 year Period (with Green Incentives)	$1,092,900
Projected Total Revenue over 50 year Period (without Green Incentives)	$651,800
Estimated NPV of Savings (with Green Incentives)	-$1,364,100
Estimated NPV of Savings (without Green Incentives)	-$1,805,200

Conclusion

The Peet Road site has plenty of available space and access for a potential hydro generation facility. However, the available fluctuating head at the site does not justify hydro generation. The expensive Kaplan style turbine required for the site drives the total construction cost and annual operating and maintenance costs so far up that the site does not offer a NPV of savings even with Green Energy incentives considered. The Peet Road site is not feasible for hydro power generation.

4.5 EVALUATION CONCLUSIONS

Out of the forty-one (41) potential sites initially investigated for in-conduit energy recovery, thirteen (13) showed potential for hydro power generation. These thirteen (13) sites were then assessed with a high level evaluation process to determine the estimated planning level development costs and projected revenue. Based on these costs, it was determined that the in-conduit hydro generation potential was either feasible, only feasible with Green incentives or is not feasible. The evaluation conclusions for the eight treated water sites and associated scenarios within the SCVWD system is summarized in Table 15. The evaluation conclusions of the five raw water sites are summarized in Table 16.

Table 15 Treated Water Sites Summary of Conclusions for the Hydro Generation Evaluation.

TREATED WATER SITE AND SCENERIO	PLANT CAPACITY FACTOR	ANNUAL PRODUCTION	ESTIMATED NPV OF SAVINGS WITH GREEN INCENTIVES	ESTIMATED NPV OF SAVINGS WITHOUT GREEN INCENTIVES	FEASIBILITY OF IN-CONDUIT HYDRO GENERATION
Hostetter Turnout: (Buried facility)					
Downstream pressure of 20 psi	0.60	2,150MWh	$4,839,100	$1,443,900	Feasible
Downstream pressure of 40 psi	0.60	1,750MWh	$3,589,600	$823,900	Feasible
Downstream pressure of 80 psi	0.59	950MWh	$1,169,300	-$334,600	Only Feasible with Green
Ocala Turnout: (Above ground facility)					
Downstream pressure of 20 psi	0.72	1,190MWh	$2,423,900	$552,900	Feasible
Downstream pressure of 40 psi	0.72	950MWh	$1,698,600	$190,200	Feasible
Downstream pressure of 80 psi	0.70	500MWh	$296,900	-$484,800	Only Feasible with Green Energy Incentives
Ocala Turnout: (Buried facility)					
Downstream pressure of 20 psi	0.72	1,190MWh	$2,265,000	$394,000	Feasible
Downstream pressure of 40 psi	0.72	950MWh	$1,554,300	$45,900	Feasible
Downstream pressure of 80 psi	0.70	500MWh	$188,800	-$592,900	Only Feasible with Green Energy Incentives
Alum Rock Turnout: (Above ground facility)					

TREATED WATER SITE AND SCENERIO	PLANT CAPACITY FACTOR	ANNUAL PRODUCTION	ESTIMATED NPV OF SAVINGS WITH GREEN INCENTIVES	ESTIMATED NPV OF SAVINGS WITHOUT GREEN INCENTIVES	FEASIBILITY OF IN-CONDUIT HYDRO GENERATION
Downstream pressure of 20 psi	0.57	1,460MWh	$2,964,000	$656,500	Feasible
Downstream pressure of 40 psi	0.57	1,160MWh	$2,040,700	$207,200	Feasible
Downstream pressure of 80 psi	0.56	560MWh	$286,600	-$597,200	Only Feasible with Green Energy Incentives
Alum Rock Turnout: (Buried facility)					
Downstream pressure of 20 psi	0.57	1,460MWh	$2,749,000	$441,500	Feasible
Downstream pressure of 40 psi	0.57	1,160MWh	$1,847,700	$14,200	Feasible
Downstream pressure of 80 psi	0.56	560MWh	$148,200	-$735,600	Only Feasible with Green Energy Incentives
Pinos Turnout: (Above ground facility)					
Downstream pressure of 20 psi	0.65	1,280MWh	$2,558,500	$544,800	Feasible
Downstream pressure of 40 psi	0.65	1000MWh	$1,692,200	$117,800	Feasible
Downstream pressure of 80 psi	0.63	440MWh	$45,300	-$642,400	Only Feasible with Green Energy Incentives
Pinos Turnout: (Buried facility)					
Downstream pressure of 20 psi	0.65	1,280MWh	$2,373,400	$359,700	Feasible
Downstream pressure of 40 psi	0.65	1000MWh	$1,526,900	-$47,500	Only Feasible with Green
Downstream pressure of 80 psi	0.63	440MWh	-$67,400	-$755,100	Not Feasible
Skyway Turnout: (Buried facility)					
Downstream pressure of 20 psi	0.69	1,340MWh	$2,636,300	$523,200	Feasible
Downstream pressure of 40 psi	0.68	1,000MWh	$1,719,500	$73,200	Feasible
Downstream pressure of 80 psi	0.65	440MWh	-$31,600	-$728,300	Not Feasible
Santa Clara Turnout: (Above ground facility)					
Downstream pressure of 20 psi	0.76	820MWh	$1,338,800	$49,000	Feasible

TREATED WATER SITE AND SCENERIO	PLANT CAPACITY FACTOR	ANNUAL PRODUCTION	ESTIMATED NPV OF SAVINGS WITH GREEN INCENTIVES	ESTIMATED NPV OF SAVINGS WITHOUT GREEN INCENTIVES	FEASIBILITY OF IN-CONDUIT HYDRO GENERATION
Downstream pressure of 40 psi	0.75	640MWh	$789,000	-$221,600	Only Feasible with Green Energy Incentives
Downstream pressure of 80 psi	0.62	250MWh	-$374,200	-$777,200	Not Feasible
Cox Turnout: (Above ground facility)					
Downstream pressure of 20 psi	0.56	430MWh	-$72,300	-$752,800	Not Feasible
Downstream pressure of 40 psi	0.55	150MWh	-$666,700	-$901,300	Not Feasible
Cox Turnout: (Buried facility)					
Downstream pressure of 20 psi	0.56	430MWh	-$195,900	-$876,400	Not Feasible
Downstream pressure of 40 psi	0.55	150MWh	-$734,100	-$968,700	Not Feasible
Congress Turnout: (Above ground facility)					
Downstream pressure of 20 psi	0.47	320MWh	-$419,900	-$919,000	Not Feasible
Downstream pressure of 40 psi	0.46	120MWh	-$762,700	-$952,400	Not Feasible
Congress Turnout: (Buried facility)					
Downstream pressure of 20 psi	0.47	320MWh	-$532,900	-$1,032,000	Not Feasible
Downstream pressure of 40 psi	0.46	120MWh	-$828,600	-$1,018,300	Not Feasible

Table 16 Raw Water Sites Summary of Conclusions for the Hydro Generation Evaluation.

RAW WATER SITE AND SCENERIO	PLANT CAPACITY FACTOR	ANNUAL PRODUCTION	ESTIMATED NPV OF SAVINGS WITH GREEN INCENTIVES	ESTIMATED NPV OF SAVINGS WITHOUT GREEN INCENTIVES	FEASIBILITY OF IN-CONDUIT HYDRO GENERATION
Half Road and Madrone Turnout	0.56	940MWh	$1,393,600	-$88,700	Only Feasible with Green Energy Incentives
Uvas Reservoir Outlet	0.59	630MWh	$478,700	-$513,700	Only Feasible with Green Energy Incentives
Vasona 805 Valve (Francis type turbine)	0.45	840MWh	$549,000	-$769,200	Only Feasible with Green Energy Incentives
Vasona 805 Valve (Kaplan type turbine)	0.23	900MWh	-$986,100	-$2,403,100	Not Feasible
Calero Modulation Valve	0.35	690MWh	-$365,900	-$1,449,000	Not Feasible
Peet Road Valve	0.22	280MWh	-$1,364,100	-$1,805,200	Not Feasible

FINAL

ENERGY OPTIMIZATION PLAN

PV Feasibility Study

B&V PROJECT NO. 178292

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PREPARED FOR

Santa Clara Valley
Water District

27 FEBRUARY 2013

BLACK & VEATCH
Building a world of difference.

Table of Contents

1.0 Executive Summary 1-1
1.1 Energy PurchAses & Requirements 1-1
1.2 Review and Update to 2001 Report 1-2
1.3 Site Overview 1-3
1.3.1 Climate 1-4
1.3.2 Solar Resource 1-4
1.3.3 Site 1 1-5
1.3.4 Site 2 1-5
1.3.5 Site 3 1-6
1.3.6 Site 4: Penitencia Water Treatment Plant 1-6
1.3.7 Site 5: Santa Teresa Water Treatment Plant 1-6
1.4 Technical Potential 1-7
1.5 Production Estimate 1-7
1.6 Financial analysis 1-8
1.6.1 Development Approaches 1-9
1.6.2 Financial Analysis 1-9
1.7 Conclusions 1-11
2.0 Introduction 2-1
2.1 Energy Purchases & Requirements 2-1
3.0 Review and Update to 2001 Report 3-1
3.1.1 Summary of 2001 Report 3-1
3.1.2 Summary of Potential Solar Projects & Costs 3-2
3.2 Recommended Updates to 2001 Report 3-4
3.2.1 Installations since 2001 3-4
3.2.2 Capital and O&M Costs 3-5
3.2.3 Emissions Offset 3-5
4.0 Site Overview 4-1
4.1 Climate 4-2
4.2 Solar Resource 4-5
4.2.1 Datasets 4-5
4.2.2 Solar Resource Analysis 4-7
4.3 Site 1 4-9
4.4 Site 2 4-11
4.5 Site 3 4-13
4.6 Site 4: Penitencia Water Treatment Plant 4-15
4.7 Site 5: Santa Teresa Water Treatment Plant 4-17
5.0 Technical Potential 5-1
5.1 Site 1 5-2

5.2 Site 2 5-3
5.3 Site 3 5-5
5.4 Site 4: Penitencia Water Treatment Plant 5-6
5.5 Site 5: Santa Teresa Water Treatment Plant 5-7
6.0 Production Estimate Results 6-1
6.1 Greenhouse Gas Emissions Benefits 6-2
7.0 Financial Analysis 7-1
7.1 Renewable Energy Financial incentives 7-1
7.1.1 Federal Incentives 7-1
7.1.2 State Incentives 7-2
7.2 Development Approaches 7-3
7.2.1 Build and Own 7-3
7.2.2 Power Purchase Agreement 7-4
7.2.3 Pre-Pay Power Purchase Agreement 7-4
7.2.4 Sale and Leaseback (not included in financial analysis) 7-5
7.3 Financial Analysis 7-6
7.3.1 Approach 7-7
7.3.2 Assumptions 7-7
7.3.3 Site 1, 2 and 3 (Scenario 1) 7-10
7.3.4 Site 4 and 5 (Scenarios 2 and 3) 7-10
8.0 Conclusions 8-1

LIST OF TABLES

Table 1-1 System Size Summary from 2001 Report 1-2
Table 1-2 Annual Emissions Offset by Solar PV in California 1-3
Table 1-3 Summary of Project Locations 1-4
Table 1-4 Solar Resource Sources 1-5
Table 1-5 Overall Site Summary 1-7
Table 1-6 Production Estimate Results 1-8
Table 1-7 NPV Results 1-11
Table 3-1 System Size Summary from 2001 Report 3-1
Table 3-2 Avoided emissions and resource consumption for a 100 kW solar PV system over 30 years 3-2
Table 3-3 Summary of Potential Projects 3-3
Table 3-4 Capital and O&M Cost Update 3-5
Table 3-5 Annual Emissions Offset by Solar PV in California 3-6
Table 4-2 Summary of Weather Conditions 4-3
Table 4-3 Solar Resource Methodology 4-6
Table 4-4 Solar Resource Sources 4-8
Table 5-1 Overall Site Summary 5-2
Table 6-1 Production Estimate Results 6-2
Table 7-1 Past and Current CSI PBI Rates ($/kWh) 7-3
Table 7-2 Cost Estimates 7-8
Table 7-3 Financial Analysis Assumptions 7-9
Table 7-4 Site 1, 2 and 3 NPV Results (Scenario 1) 7-10
Table 7-5 Site 4 and 5 NPV Results (Scenarios 2 and 3) 7-11
Table 8-1 Overall Site Summary 8-1
Table 8-2 NPV Results 8-2

LIST OF FIGURES

Figure 4-1 SCVWD Solar PV Site Locations 4-2
Figure 4-2 Average Monthly Temperatures for San Jose, CA (Source: Weatherbase.com) 4-3
Figure 4-3 Average Monthly Rainfall for San Jose, CA (Source: Weatherbase.com) 4-4
Figure 4-4 Applicable Datasets near sites (Source: Google Earth, accessed Oct. 2012) 4-7
Figure 4-5 Site 1 Location 4-9
Figure 4-6 Ground View of Site 1 4-10
Figure 4-7 Site 2 Location 4-11
Figure 4-8 Ground View of Site 2 4-12
Figure 4-9 Site 3 Location 4-13
Figure 4-10 Ground View of Site 3 4-14
Figure 4-11 Site 4 (PWTP) Location 4-15
Figure 4-12 Ground View of Site 4 4-16
Figure 4-13 Site 5 (STWTP) Site Location 4-17
Figure 4-14 Ground View of Site 5 4-18
Figure 5-1 Site 1 Conceptual Layout 5-3
Figure 5-2 Site 2 Conceptual Layout 5-4
Figure 5-3 Site 3 Conceptual Layout 5-5
Figure 5-4 PWTP Conceptual Layout 5-6
Figure 5-5 STWTP Conceptual Layout 5-8

ACRONYMS

AC	Alternating Current
CSI	California Solar Initiative
DC	Direct Current
GHI	Global Horizontal Irradiance
ITC	Investment Tax Credit
kWac	Kilowatt AC capacity of a system as seen by the revenue grade meter
kWdc	Kilowatt DC capacity of the solar PV array, before inverters
kWh	Kilowatt-hour
kWp	Kilowatt-peak (DC)
MACRS	Modified Accelerated Depreciation
MW	Megawatt
MWh	Megawatt-hour
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PPA	Power Purchase Agreement
PV	Photovoltaic
PWRPA	Power and Water Resources Pooling Authority
PWTP	Penitencia Water Treatment Plant
RWTP	Rinconada Water Treatment Plant
SCVWD	Santa Clara Valley Water District
STWTP	Santa Teresa Water Treatment Plant
TGY	Typical GHI Year
TMY	Typical Meteorological Year
Wp	Watt-peak (DC)

1.0 Executive Summary

Santa Clara Valley Water District (SCVWD) has various treatment, pumping and office facilities and owns properties and land throughout the Santa Clara County region. In 2001, SCVWD studied the feasibility of solar photovoltaic (PV) at various facilities and installed 200 kW rooftop and carport solar PV systems at Almaden Campus in 2004. Black & Veatch was retained to review the economic viability of installing new solar PV generating systems at five locations. This report studies the feasibility of solar PV projects at these locations and reviews the 2001 analysis and recommends updates.

The sites identified by SCVWD and studied by Black & Veatch include three undeveloped parcels of land with no SCVWD load (Sites 1, 2, and 3). The remaining two sites are open areas and water basins at existing water treatment plants (Sites 4 and 5). The analysis in this report includes assessing the site climate and solar resource; Black & Veatch also studied technical potential, or essentially how many kilowatts (kW) of solar PV capacity could feasibly be installed at each site; and finally Black & Veatch studied the economics of installing solar PV at each site with three different development approaches and three scenarios which assumed different value for the solar energy.

1.1 ENERGY PURCHASES & REQUIREMENTS

SCVWD purchases most of its energy from the Power and Water Resources Pooling Authority (PWRPA). There are four specific regulatory requirements in the State of California that affect any public electric utility including PWRPA operations. They include (1) Resource Adequacy (RA) mandated by the California Independent System Operator (ISO); (2) Public Purpose Program (P3) funds mandated by the State of California; (3) California Renewable Portfolio Standard (RPS) mandated by Senate Bill X1-2; and (4) Green House Gas (GHG) regulations mandated by AB 32, the Global Warming Solutions Act of 2006.

1) Resource adequacy is a State of California mandated planning and procurement process to ensure adequate electrical resources are available to serve all customers in real time. It requires PWRPA to prudently plan for and procure resources that are adequate to meet its peak demand and a 15 percent planning reserve margin.
2) AB 995 also requires PWRPA to set aside a fixed percentage of its retail service revenue into a Public Purpose Program fund (P3 fund). P3 money is to be used to fund any or all of the following public purpose programs: (1) cost-effective demand-side management services to promote energy efficiency and energy conservation; (2) new investment in renewable energy resources and technologies; and (3) research, development, and demonstration programs for the public interest.
3) SB X1-2 requires PWRPA to implement and enforce a new renewable energy portfolio standard including a requirement to implement minimum procurement targets for procuring eligible renewable resources. It is unclear if PWRPA must meet this obligation for

its total load, or just for the amount of power greater than its WAPA allotment. The California Energy Commission will make a determination on this issue shortly. Initially, PWRPA is on target to meet the 20 percent renewable portfolio standard (RPS) goal SCVWD's Almaden campus solar project is counted as one of the eligible renewable sources.

4) The California Air Resources Board (CARB) is finalizing regulations to implement AB 32—the Green House Gas (GHG) legislation. The AB 32 draft identifies a cap-and-trade program as one of the GHG emission reduction strategies for California. Under cap-and-trade, an overall limit (the Cap) on GHG emissions is established for all capped sectors. Facilities subject to the cap can reduce GHGs, receive permits (allowances) for their reductions, and then trade them on the open market. Power generation is a capped sector subject to this program, and the regulation will apply to PWRPA.

1.2 REVIEW AND UPDATE TO 2001 REPORT

The 2001 Report, titled "Distributed Electrical Generation with Renewable Solar Energy at Almaden Headquarters Campus and Rinconada Water Treatment Plant" (2001 Report), was prepared to address the Board's interest in installing solar PV systems on rooftops and parking lots to partially offset electricity usage at various properties. The report identified 1,334 kW of potential solar PV capacity at the Almaden and Rinconada (RWTP) sites; the sizes and estimated costs of these systems are summarized in the table below.

Table 1-1 System Size Summary from 2001 Report

PROJECT LOCATION	PROJECT SIZE	INSTALLED COST ($)	COST PER WATT ($/W)
Almaden Campus			
New Water Quality Lab Roof	120 kW	$1,100,000	$9.17
HQ Bldg Roof	90 kW	$880,000	$9.78
Blossom Hill Annex Roof	90 kW	$880,000	$9.78
Carports in the Parking	98 kW	$900,000	$9.18
Admin Bldg Roof	136 kW	$1,250,000	$9.19
Subtotal	534 kW	$5,010,000	$9.38
RWTP Reservoir Roof	800 kW	$7,100,000	$8.88
Total	**1,334 kW**	**$12,110,000**	**$9.08**

Over the past several years the capital cost of solar PV systems has dropped significantly. In 2012, systems of the size presented in the table above would range from $5.50-$7.00 per watt for a roof mount or ground-mount installation. Carport installations are more expensive, ranging from $4.50-$7.00 per watt. The O&M costs estimated in the 2001 Report are very low. Black & Veatch recommends a value ranging from $15.00 - $30.00 per kilowatt.

The share of renewable generation in the California electricity mix has significantly increased since the 2001 Report. The table below provides updated estimates to emissions offsets.

Table 1-2 Annual Emissions Offset by Solar PV in California

ANNUAL EMISSIONS OFFSET	2001 REPORT	2012 UPDATED*
Carbon Dioxide (CO_2) – lbs per kW installed	4,520.00	1,250.00
Nitrogen Oxides (NO_x) – lbs per kW installed	1	2.89
Carbon Dioxide (CO_2) – lb/MWh	-	658.68
Nitrogen Oxides (NO_x) – lb/MWh	-	0.42
Sulfur dioxide (SO_2) – lb/MWh	-	0.18

***Source: EPA eGRID 2012 Version 1.0, WECC California Grid**
The same system parameters as the 2001 Report were used to calculate annual lbs/kW emissions for the 2012 Updated values.

In 2011, PWRPA reported that the electricity delivered to SCVWD had created 54 pounds of CO_2e (Carbon Dioxide equivalent emissions[1]) emissions for every MWh delivered.

1.3 SITE OVERVIEW

Black & Veatch has reviewed the climate, solar resource, and other attributes at each of the five sites related to development of a solar PV project (site topography, neighborhood, interconnection access, site access). Note that access to interconnection facilities is discussed, however it was beyond the scope of this study to assess the available capacity for interconnection. The site locations and areas are summarized in the table below. Sites 1, 2, and 3 are open plots of land that are currently unused. Site 4, PWTP, is an open ground area at SCVWD's Penitencia Water Treatment Plant, and Site 5, STWTP, is two open ground areas and two water basins at SCVWD's Santa Teresa Water Treatment Plant.

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[1] Carbon Dioxide equivalent (CO2e) is a metric measurement of the emissions from various greenhouse gases that is based on their global warming potential.

Table 1-3 Summary of Project Locations

Site Name	Latitude/ Longitude	Address	Closest Population Center	Acres of available space
Site 1	37.34°/-121.78°	2321-2341 Klein Rd, San Jose, CA 95148	San Jose	10.8
Site 2	37.19°/-121.69°	Coyote Creek Golf Dr & U.S. 101 San Jose, CA 95037	Morgan Hill	17.7
Site 3	37.11°/-121.61°	956-1028 Maple Ave Morgan Hill, CA 95037	Morgan Hill	15.3
Site 4: PWTP	37.40°/-121.83°	3959 Whitman Way, San Jose, CA 95132	San Jose	0.7
Site 5: STWTP	37.22°/-121.84°	7011 Graystone Lane, San Jose, CA 10120	San Jose	2.6

1.3.1 Climate

The sites typically have hot summers with little rain, while the winters are typically cool and mild with moderate rainfall. Temperatures average 59.8 degrees Fahrenheit over the year. Summer highs reach 81 degrees, while winter lows reach 41 degrees. The sites average approximately 14.6 inches of rain each year.

1.3.2 Solar Resource

Black & Veatch assessed several solar resource datasets from various databases to determine which dataset is most representative of the conditions at each site. The datasets considered most adequate to represent the solar resource at each site are TGY (Typical Global Horizontal Irradiance (GHI) Year) datasets. These datasets were chosen because of their proximity to the site, and quality of data. The distance to each site for TGY data is zero because the solar resource measurement is made using satellite data at the site location. The typical annual GHI of the five sites range from 1,877 to 1,896 kWh/m^2. The TGY datasets are summarized in the table below.

Table 1-4 Solar Resource Sources

Location	Latitude	Longitude	Source	Distance to Site (mi)*	Typical Annual GHI (kWh/m2)
Site 1	37.34	-121.78	TGY	0	1,896
Site 2 and 3	37.19	-121.69	TGY	0	1,894
Site 4: PWTP	37.40	-121.83	TGY	0	1,877
Site 5: STWTP	37.22	-121.84	TGY	0	1,896

1.3.3 Site 1

Site 1 consists of 10.8 acres of available land that slopes slightly to the southwest and is primarily grass land. The site does not have any large structures or trees that would need to be removed prior to construction, therefore the site ground prep-work required will likely be minimal. Black & Veatch notes that there is a southward slope of the land that can be advantageous to a solar PV project. The site is located approximately 6 miles east of downtown San Jose, along Pleasant Acres Drive and Klein Road in a residential neighborhood. Considerations should be made to assess the impact on the community in regards to noise and glare originating from the solar PV system. A solar PV installation would have to be approved by local permitting authorities, but it is expected that there should not be any significant permitting issues. The roads that provide access to the site are narrow and may present some challenges for large trucks and heavy equipment during the procurement and construction process. Special permits and permissions may be needed in order for construction vehicles to pass through the residential neighborhood surrounding the site. It is assumed that a PG&E distribution line is accessible for interconnection of a solar PV facility.

1.3.4 Site 2

Site 2 consists of 17.7 acres of available land that slopes very slightly to the south and is primarily grass land with a few small trees in the south east area of the site. There is approximately 15 feet of elevation drop between the highest point in the north part of the site and the lowest point in the south part of the site. The site is not located in a residential neighborhood and is primarily surrounded by grassland and US 101. A solar PV installation would have to be approved by local permitting authorities, but it is expected that there should not be any significant permitting issues.

There appears to be some type of facility (possibly a natural gas pipeline) entering the site from the northwest corner of the site, near the US 101 onramp entrance. The site is located approximately 15 miles southeast of downtown San Jose and 5 miles northwest of Morgan Hill along Coyote Creek Golf Drive and US 101. The site is accessible via Coyote Creek Golf Drive, which is likely not a heavily used road and should not present any major challenges to large trucks and heavy machinery travelling to the site. The site is adjacent to transmission lines and within a mile of industrial and residential facilities and will be accessible for interconnection.

1.3.5 Site 3

Site 3 consists of 15.3 acres of generally flat land and is primarily grassland with an area of small trees in the eastern most section of the site. The site is located approximately 22 miles southeast of downtown San Jose and 2.5 miles southeast of Morgan Hill, along Maple Avenue and Murphy Avenue in a residential neighborhood. Considerations should be made to assess the impact on the community in regards to noise and glare originating from the solar PV system. A solar PV installation would have to be approved by local permitting authorities, but it is expected that there should not be any significant permitting issues. The site is primarily accessible via Murphy Avenue, which can be accessed from Tennant Avenue and is in close proximity to US 101. The roads to the site should not present any major challenges to large trucks and heavy machinery travelling to the site. As mentioned above, the site is adjacent to residential property. It is expected that a PG&E distribution line will be in the vicinity of the site.

1.3.6 Site 4: Penitencia Water Treatment Plant

The Penitencia Water Treatment Plant (PWTP) Site 4 consists of 0.7 acres of available land that slopes slightly to the southwest and is primarily grass with a few small trees along the northeast edge of the area. There is approximately 10 feet of elevation drop between the highest point in the northeast part of the site and the lowest point in the southwest part of the site. The site is located approximately 6 miles northeast of downtown San Jose along Vista Del Mar and Whitman Way. The site is located near a residential neighborhood but is primarily surrounded by the treatment plant structure(s), trees and grassland. The site is accessible via Whitman Way, which can be accessed from Piedmont Road and in close proximity to Interstate 680. The roads to the site should not present any major challenges to large trucks and heavy machinery travelling to the site. It is assumed that the solar PV system will interconnect locally into the PWTP electrical infrastructure.

1.3.7 Site 5: Santa Teresa Water Treatment Plant

The Santa Teresa Water Treatment Plant (STWTP) Site 5 consists of 2.6 acres of available open land and roof space above sedimentation basins. For the two sites on open land there is approximately 10 feet of elevation drop between the highest point in the north part of the areas and the lowest point in the south part of the areas. The site is located approximately 9 miles south east of downtown San Jose along Graystone Lane. The site is located near a residential neighborhood but is primarily surrounded by the treatment plant structure(s), trees and grassland. The site is accessible via Graystone Lane, which can be accessed from the Almaden Expressway. The road to the site should not present any major challenges to large trucks and heavy machinery travelling to the site. It is assumed that the solar PV system will interconnect locally into the STWTP electrical infrastructure. There is not a significant amount of trees surrounding the proposed ground-mount locations; however there are some trees that may shade modules located in the southern portion of the eastern most area. The two locations on water basins appear to require some pre-work to make the sites suitable for installation of a solar PV system.

1.4 TECHNICAL POTENTIAL

Black & Veatch assessed the technical feasibility of installing solar at each of the sites, and the potential capacity at each site. The proposed development consists of fixed ground-mounted PV systems at five sites located in Santa Clara County, California, identified by the SCVWD. Black & Veatch assumed the land parcels will be graded to be suitable enough for a fixed-tilt racking system. For all sites except Site 5, Black & Veatch assumed a zero degree azimuth (facing due south). This assumption was chosen as it generally allows the energy production to be maximized. Site 5 would have a smaller kW capacity if a zero degree azimuth was chosen; therefore, this convention was not followed because the array layout of a zero degree azimuth would not be optimal for the available spaces at site 5.

Black & Veatch notes that after the site selection is narrowed, a detailed analysis would need to be performed in order to identify the optimal azimuth and system design. A summary of potential system sizes and available land for PV development is presented in Table 1-5.

Table 1-5 Overall Site Summary

NAME	DESCRIPTION	AREA (ACRES*)	CAPACITY (KWP) **	CAPACITY (KW AC)
Site 1	Fixed Ground Mount PV Site 1	10.8	2,938	2,520
Site 2	Fixed Ground Mount PV Site 2	17.7	4,496	3,700
Site 3	Fixed Ground Mount PV Site 3	15.3	3,906	3,200
Site 4	Penitencia Water Treatment Plant Fixed Ground Mount PV	0.7	165	146
Site 5	Santa Teresa Water Treatment Plant Fixed Ground Mount PV	2.6	820	720

*** Area of PV modules, racking and clear row spacing.**
**** kWp refers to the kW peak (or dc rating of the system).**

If consideration of development for these sites does not occur for several years, then the sites will need to be re-evaluated to determine if there are any changes in land-use, surrounding development, permitting changes, or technological advances that will impact the technical feasibility of each site.

1.5 PRODUCTION ESTIMATE

Black & Veatch estimated the energy production of the proposed facilities described above. The production values are net yields anticipated at the point of interconnection and include estimated annual losses (soiling, auxiliary loads, voltage drop, etc). The production is summarized in the table below. The numbers below represent typical performance for systems in the Santa Clara County area.

Table 1-6 **Production Estimate Results**

SITE	FIRST YEAR GENERATION (MWH/YEAR)[A]	2011 ENERGY USE AT SITE (MWH)[B]	DC CAPACITY FACTOR	AC CAPACITY FACTOR[C]	ANNUAL YIELD (KWH/KWP)	PERFORMANCE RATIO
Site 1	4,901	0	19.2%	22.3%	1,678	78.7%
Site 2	7,552	0	19.3%	23.4%	1,689	79.0%
Site 3	6,531	0	19.2%	23.4%	1,681	78.7%
Site 4 PWTP	272	1,659	18.9%	21.4%	1,659	78.0%
Site 5 STWTP	1,375	2,046	19.3%	22.0%	1,692	79.3%

Notes:
A First year generation represents the expected energy generation of the system during its first year of operation. This does not reflect the generation over the expected lifetime of the project.
B Sites 1, 2 and 3 do not currently have SCVWD loads. The PWTP and STWTP consume energy; in 2011 the annual energy consumption at these sites is listed in the table above. As can be seen, the solar PV generation would partially offset this load, but not completely.
C The ac capacity factor is calculated using the inverter nameplate rating.

Future development of the sites and surrounding land may impact the production potential by introducing structures that can cause shading on the areas being considered for PV systems. A complete shading analysis prior to system design will identify potential losses due to shading. The lifetime of a solar PV system is considered to be 20 to 25 years and is based on the typical module warranty of most manufacturers.

Based on a report provided by PWRPA to SCVWD assumes each MWh of energy produces 52 pounds of CO2e emissions. Assuming the maximum capacity at Sites 1 through 5, the systems could offset just over 1,114,000 pounds of CO2e emissions during the first year when taking into account the 20,631 MWh of technical generation potential.

1.6 FINANCIAL ANALYSIS

There are several approaches to developing a solar PV project. Major factors in the development approaches are the ability to take advantage of financial incentives. Each development option has certain benefits regarding financing costs, use of tax incentives, project control; and certain risks regarding financial risks, and development/construction risks.

The applicable and available tax incentives are described here:

- **Investment Tax Credit (ITC)** - a corporate tax credit. With reference to solar PV installations, consists of a tax credit valued at 30 percent of the project cost basis with no maximum credit limitations. May only be claimed by a taxable entity who owns the generating facility.
- **Modified Accelerated Depreciation (MACRS)** – certain investments in biomass, solar, wind, and geothermal can be recovered through accelerated depreciation deductions. Certain power plant equipment may qualify for 5-year 200 percent declining-balance depreciation. Eligibility is the same as the ITC.
- **California Solar Incentives (CSI)** - this program provides rebates to customers of an investor owned utility (IOU) in California. Participants can be paid based on the performance of the system. The rebate rate is stepped down as the program is used and is currently in the last step of the program.

1.6.1 Development Approaches

There are several approaches to developing a solar PV facility. Four venues that are prevalent or applicable to SCVWD are discussed here:

- **Build and Own** – SCVWD has the option to own the project themselves, and enter into an Engineer, Procure, Construct (EPC) contract with a partner to develop the project. SCVWD would not be able to take advantage of any tax incentive programs that are available to assist in funding renewable energy projects.
- **Power Purchase Agreement**– The purchase of renewable energy through a power purchase agreement (PPA) with a developer is the most common way in which renewable energy projects have been developed in the recent past. PPAs provide low-risk delivery of power to the purchaser, usually for a set cost per unit of energy, while largely shielding the purchaser from project risks.
- **Pre-pay Power Purchase Agreement** - The PPA pre-payment option follows the general form of a conventional PPA; however, payment for all or part of the power is made in one lump sum at the beginning of the PPA term. SCVWD would likely make ongoing payments for electricity beyond the pre-paid amount and possibly a portion of the O&M costs.
- **Sale and Leaseback** - The sale/leaseback project structure can take on a number of forms. One option would involve SCVWD developing the facility and selling it to an investor who has interest in claiming the ITC credit at, or within 3 months of, the in-service date. The investor would then lease the property back to SCVWD for a period less than the useful life of the plant. SCVWD would have the option to purchase the property at a fair market value at the end of the lease term. This approach is very similar to the PPA approach and is therefore not included in the financial analysis of this report.

1.6.2 Financial Analysis

Black & Veatch developed a pro forma analysis to calculate the net present value (NPV) for the different development approaches described above, excluding the sale and leaseback approach, in three different scenarios:

1) For Sites 1, 2 and 3 the PG&E feed in tariff (FIT) rate is assumed to be available to the project, and equal to the value of the solar energy. In this scenario, a PPA or pre-pay PPA with a developer is not necessarily applicable. Black & Veatch includes this case, however because an agreement could be made with a developer (such as a lease agreement) where the economics are the same as a PPA or pre-pay PPA.
2) For Sites 4, and 5, the first scenario assessed assumes the value of solar energy is the aggregate value of the PWRPA energy charges offset by the PV system in a year.
3) The final scenario assessed for Sites 4 and 5 assumes the value of solar energy is the aggregate value of PG&E E-19 energy charges offset by the solar PV system.

The results of this analysis are summarized in the table below. As expected, the build and own case is the most expensive. This is largely driven by the inability to take advantage of the ITC and MACRS incentives. The general trend shows that systems that use the pre-pay PPA approach are more economical, and systems that value solar energy with PG&E E-19 rate schedule, appear more financially attractive. The larger sites (Sites 1, 2 and 3) may also make economic sense with the pre-pay PPA approach.

Table 1-7 NPV Results

SITE	DEVELOPMENT APPROACH	NPV OF SAVINGS WITH PV ($000) * (SCENARIO 1)	
Site 1	Build and Own	-$3,499	
	PPA	-$1,497	
	Pre-Pay PPA	$190	
Site 2	Build and Own	-$5,199	
	PPA	-$2,130	
	Pre-Pay PPA	$465	
Site 3	Build and Own	-$4,529	
	PPA	-$1,869	
	Pre-Pay PPA	$381	
SITE	**DEVELOPMENT APPROACH**	**NPV OF SAVINGS WITH PV ($000) * (SCENARIO 2)**	**NPV OF SAVINGS WITH PV ($000) * (SCENARIO 3)**
Site 4 PWTP	Build and Own	-$93	$113
	PPA	-$79	$206
	Pre-Pay PPA	$26	$295
Site 5 STWTP	Build and Own	-$798	$809
	PPA	-$209	$1,234
	Pre-Pay PPA	$288	$1,649

1.7 CONCLUSIONS

SCVWD has investigated solar PV feasibility in 2001 and installed solar PV facilities successfully in 2004. The market has changed significantly since the 2001 analysis performed by SCVWD. The value of offset emissions has decreased, but the cost of solar PV systems has also decreased. The O&M cost assumptions were fairly low.

Currently, SCVWD has several sites that are suitable for the development of a solar PV facility. The economics of developing these facilities varies based on several parameters such as the development approach, system size, and assumptions regarding the value of solar energy. Black & Veatch performed an analysis which would show the benefits of different development approaches under various assumptions regarding the value of solar energy. It is clear that the Pre-Pay PPA approach is the most economical. Black & Veatch would recommend this approach if SCVWD has upfront capital, but notes that this type of structure is complicated and may incur several fees. Alternately, the PPA option is widespread and appropriate for SCVWD. Alternately, the PPA option is widespread and appropriate for SCVWD however based on the results presented below does not appear to be a financially attractive approach at this time. Based on the results shown above, Sites 4 and 5 appear to be financially viable under a pre-pay PPA approach in Scenario 2. Sites 4 and 5 appear to be financially attractive under build-and-own, PPA and pre-pay PPA in scenario 3. The larger sites (Sites 1, 2 and 3) may also make economic sense with the pre-pay PPA approach (scenario 1).

2.0 Introduction

Santa Clara Valley Water District (SCVWD) has various treatment, pumping and office facilities and owns properties and land throughout the Santa Clara County region. In 2001, SCVWD studied the feasibility of solar photovoltaic (PV) at various facilities and installed 200 kW rooftop and carport solar PV systems at Almaden Campus in 2004. SCVWD is interested in exploring further opportunities for solar PV generation and has retained Black & Veatch to review the economic viability of installing solar PV systems at five locations. This report evaluates the feasibility of solar PV projects at five proposed locations and brief reviews of the earlier report. SCVWD purchases most of its energy from the Power and Water Resources Pooling Authority (PWRPA) at a lower energy rates as compared to PG&E.

PWRPA serves SCVWD electric load at retail employing a Wholesale Distribution Tariff for access to PG&E distribution lines. Energy generated by SCVWD behind the meter can offset energy purchases from PWRPA. Energy generated by SCVWD not behind the meter can be sold to PWRPA directly and SCVWD can benefit from that energy through its retail service from PWRPA. In addition, there are potential financial benefits to offsetting emissions through the use of solar PV. The sites identified by SCVWD and studied by Black & Veatch included three undeveloped parcels of land with no SCVWD load (Sites 1, 2, and 3), and two sites at existing water treatment plants[1] which are open areas and water basins (Sites 4 and 5). The analysis in this report includes assessing the site climate and solar resource; assessing the technical potential, or essentially how many kilowatts (kW) of solar PV capacity could feasibly be installed at each site; and studying the economics of installing solar PV at the five sites with three different development approaches.

2.1 ENERGY PURCHASES & REQUIREMENTS

There are four specific regulatory requirements in the State of California that affect any public electric utility including PWRPA operations. They include (1) Resource Adequacy (RA) mandated by the California Independent System Operator (ISO); (2) Public Purpose Program (P3) funds mandated by the State of California; (3) California Renewable Portfolio Standard (RPS) mandated by Senate Bill X1-2; and (4) Green House Gas (GHG) regulations mandated by AB 32, the Global Warming Solutions Act of 2006.

Resource adequacy is a State of California mandated planning and procurement process to ensure adequate electrical resources are available to serve all customers in real time. It requires PWRPA to prudently plan for and procure resources that are adequate to meet its peak demand and a 15 percent planning reserve margin. Ideally, PWRPA would have ownership or control of actual facilities to meet these requirements. Although it has ownership of some facilities, PWRPA relies on firm, physical contracts with about ten power producers (Shell Energy, City of Roseville, Power-Ex, Iberdrola Renewable, Sonoma County Landfill, Morgan Stanley, BP Energy, Sempra Energy, Eagle Energy, EDF Trading, Barclay Bank, etc.) to partially meet this requirement. PWRPA has plans to acquire facilities over time, such as the Lodi Energy Center project, to meet the requirement.

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[1] The Rinconada Reservoir Roof will be considered in Project 93294057, RWTP Reliability Improvement Project.

AB 995, approved by Governor Gray Davis on September 30th, 2000, also requires PWRPA to set aside a fixed percentage of its retail service revenue into a Public Purpose Program fund (P3 fund). P3 money is to be used to fund any or all of the following public purpose programs: (1) cost-effective demand-side management services to promote energy efficiency and energy conservation; (2) new investment in renewable energy resources and technologies; and (3) research, development, and demonstration programs for the public interest. Each Participant is granted a three-year period to exclusively direct their contributions from the P3 fund to any qualifying projects or programs they choose. SCVWD was awarded all of its P3 contributions in the amount of $158,458 for installing a district wide power monitoring system; and replacement of motor and adjustable speed drive for the PWTP backwash pump replacement project.

SB X1-2 requires PWRPA to implement and enforce a new renewable energy portfolio standard including a requirement to implement minimum procurement targets for procuring eligible renewable resources. The procurement targets for renewable resources expressed as a percentage of total power portfolios are:

- January 1, 2011—December 31, 2013: Average of 20 percent.
- January 1, 2014—December 31, 2016: Average of 25 percent.
- January 1, 2017—December 31, 2020: Average of 33 percent.

A considerable portion of PWRPA's power, from 29 to 84 percent, is hydroelectric power produced by the USBR Central Valley Project and distributed and marketed by Western Area Power Administration (WAPA)—Attachment 2; however, this source of power is not an "eligible renewable" source under.SB X1-2. It is unclear if PWRPA must meet this obligation for its total load, or just for the amount of power greater than its WAPA allotment. The California Energy Commission will make a determination on this issue shortly. Initially, PWRPA is on target to meet the 20 percent renewable portfolio standard (RPS) goal for its total load by utilizing the power output from Sonoma County's small, 1.5 MW, Hydro facility, and numerous small solar and landfill gas projects. Each of these resources qualifies as an eligible renewable resource. SCVWD's Almaden campus solar project is counted as one of the eligible renewable sources.

The California Air Resources Board (CARB) is finalizing regulations to implement AB 32—the Green House Gas (GHG) legislation. The AB 32 draft identifies a cap-and-trade program as one of the GHG emission reduction strategies for California. Under cap-and-trade, an overall limit (the Cap) on GHG emissions is established for all capped sectors. Facilities subject to the cap can reduce GHGs, receive permits (allowances) for their reductions, and then trade them on the open market. Power generation is a capped sector subject to this program, and the regulation will apply to PWRPA. Specific impacts to PWRPA will be presented to SCVWD.

3.0 Review and Update to 2001 Report

In 2001 the Water Utility Operations Division completed a technical report that addresses the possibility of solar power installations at properties owned by the SCVWD. The report, titled "Distributed Electrical Generation with Renewable Solar Energy at Almaden Headquarters Campus and Rinconada Water Treatment Plant" (2001 Report), was prepared to address the Board's interest in installing solar PV systems on rooftops and parking lots to partially offset electricity usage at various properties. This section summarizes findings and analysis of the 2001 Report, and provides an update on the proposed solar PV systems.

3.1.1 Summary of 2001 Report

The 2001 Report identified 1,334 kW of potential solar PV capacity at the Almaden and Rinconada sites; the sizes and estimated costs of these systems were as summarized in the table below. The Almaden Campus was identified as having five potential locations for PV systems totaling 534 kW, and the potential at the Rinconada Reservoir Roof was estimated to be 800 kW (Table 3-1).

Table 3-1 System Size Summary from 2001 Report

PROJECT LOCATION	PROJECT SIZE
Almaden Campus	
New Water Quality Lab Roof	120 kW
HQ Bldg Roof	90 kW
Blossom Hill Annex Roof	90 kW
Carports in the Parking	98 kW
Admin Bldg Roof	136 kW
Subtotal	534 kW
RWTP Reservoir Roof	800 kW
Total	**1,334 kW**

The financial analysis found in Section D (Economic Considerations) of the 2001 Report determined that the All-Inclusive Cost ($/kWh) of a 121 kW solar PV project would be between $0.1443 and $0.2477 per kilowatt-hour (kWh), depending on the interest rate received for capital financing. A California Energy Commission (CEC) incentive for installing solar PV systems was identified as providing a buy-down of 50 percent of system costs or up to $4.50 per watt, which is a major factor in the total all-inclusive costs of solar PV that was presented in the report.

The benefits of installing solar PV systems were also discussed in the 2001 Report. The benefits vary depending on the location, utility and regulatory policies, and electrical infrastructure associated with the proposed project site. The "Electricity Benefits" of solar PV systems were identified in the 2001 Report as being:

- Lower electricity purchases: reduced demand from SCVWD facilities for electricity, especially in summer months when electricity rates and solar output are the highest.
- Hedge against future electricity rate spikes: Provision of an electricity generation source that hedges against the increase of electricity rates.
- Reduced pressure on the state's electrical grid: Reduced demand on the electrical grid's transmission lines will help reduce the likelihood of electricity curtailments and rolling blackouts.

The 2001 Report cited U.S. EPA estimates for the impact of solar PV on air quality and resource conservation for a 100 kW system over 30 years (Table 3-2).

Table 3-2 Avoided emissions and resource consumption for a 100 kW solar PV system over 30 years

AIR QUALITY			RESOURCE CONSERVATION		
Smog	62,783	lbs NOx	Oil	12,092	barrels, or
Acid Rain	100,453	lbs SOx	Coal	3,974	tons, or
Global Warming	7,534	Tons CO2	Natural Gas	879	Million cubic ft

The environmental benefits of solar were broken down further in Section C, CEQA Considerations, where one-kilowatt of solar energy is presented as being capable of offsetting one pound of nitrogen oxides (NO_x) and 4,520 pounds of carbon dioxide (CO_2).

3.1.2 Summary of Potential Solar Projects & Costs

The 2001 report identified five different locations for PV systems at two properties owned by SCVWD. The PV system sizes ranged from 90 kW to 800 kW in size and consisted of four rooftop systems and two carport systems. A summary of the systems as presented in the report is found below and in Table 3-3.

Almaden Headquarters

- New Water Quality Lab Roof
  - 120 kW solar PV potential
  - Exact size and type of installation was to be determined during the building Design-phase
  - Installed cost expected to be $1,100,000 ($9.17/W)
- Headquarters Building Roof
  - 90 kW solar PV potential
  - Two areas for installation: South elevation (oriented southwest) and East elevation (orientatated southeast)

  - Installed cost expected to be $880,000 ($9.76/W)
- Blossom Hill Annex Roof
  - 90 kW solar PV potential
  - Flat commercial rooftop
  - Installed cost expected to be $880,000 ($9.76/W)
- Carport Parking Lot
  - 98 kW solar PV potential (two separate carports)
  - Dual cantilevered structures proposed to provide shelter for 84 vehicles
  - Located in the main parking area parallel to the Almaden Expressway
  - Installed cost expected to be $900,000 ($9.18/W)
- Admin Building Roof
  - 136 kW solar PV potential
  - Installed cost expected to be $1,250,000

Rinconada Reservoir Roof

- 800 kW solar PV potential
- Assumed combination of roof skin and solar PV installation
- Installed cost expected to be $7,100,000 ($8.88/W)

Table 3-3 Summary of Potential Projects

PROJECT LOCATION	PROJECT SIZE (KW-AC)	INSTALLED COST ($)	COST PER WATT ($/W)
Almaden Campus			
New Water Quality Lab Roof	120	$1,100,000	$9.17
HQ Bldg Roof	90	$880,000	$9.78
Blossom Hill Annex Roof	90	$880,000	$9.78
Carports in the Parking Lot	98	$900,000	$9.18
Admin Bldg Roof	136	$1,250,000	$9.19
Almaden Campus Subtotal	534	$5,010,000	$9.38
RWTP Reservoir Roof	800	$7,100,000	$8.88
Total	**1,334**	**$12,110,000**	**$9.08**

3.2 RECOMMENDED UPDATES TO 2001 REPORT

3.2.1 Installations since 2001

Many of the proposed rooftop systems were not installed due to weaknesses in the roof's structural ability to support the PV systems. The roofs determined unsuitable for solar PV installations were the HQ Building, New Laboratory building, and RWTP roofs. Installation of solar PV at the new Water Quality Laboratory was removed from the construction scope during bidding phase. However, underground utilities were installed as a future provision for 45 kW of carport solar. Since 2001, the Almaden Campus Solar Project has installed 200 kW of generating capacity. The Rinconada Reservoir Roof will be considered in Project 93294057 (RWTP Reliability Improvement Project).

The 200 kW Almaden Campus Solar Project is composed of 2 carport structures, 57 solar arrays installed on the roof of the Administration Building, 64 solar arrays mounted on top of the two carport structures, four (4) power inverters, DC/AC disconnect switches, power distribution panel, and combiner and re-combiner boxes. The carports provide 76 shaded parking spaces for District employees. The system also includes a data acquisition system, lobby kiosk displays and four charging ports for electric vehicles.

The solar project is annually producing approximately 332,000 kWh of electricity, enough to provide for a 20 percent reduction in peak power demand at the campus and 10 percent of overall campus energy needs. The cost of the project, net of incentives totaled $2,186,040, with a useful life of 30 years. The project reduces demand on the California/PG&E power grid, provides shaded parking, reduces CO2 and other emissions and serves as a symbol of SCVWD's commitment to environmental stewardship and development of renewable energy.

In 2001 - 2004, when the Almaden Solar Project was in the planning and construction stages and initial Board discussions on project funding took place; SCVWD staff estimated the ongoing savings in utility costs as $50,000-$70,000 per year based on PG&E rates and a project payback period within the estimated 25-30 year useful life of the project. It should be noted however, that a significant change occurred in 2005, after the solar project was completed. SCVWD, as a member of PWRPA, began purchasing power, generated largely from renewable sources, at a rate that is about 50 percent less than rates charged by PG&E. SCVWD's participation in PWRPA provided immediate environmental benefits as well as actual cost savings that far exceeded the anticipated cost and environmental benefits of the solar project. Consequently, measuring the actual payback period and environmental benefits of the solar project using current information relative to current cost of PWRPA provided electricity will result in a much longer payback period and significantly less environmental benefits for the project than originally estimated.

3.2.2 Capital and O&M Costs

Capital costs for solar PV systems have declined significantly since 2001; operations and maintenance (O&M) costs have also seen a decrease. The cost assumptions made in the calculations found in Section D Economic Considerations of the 2001 Report are no longer accurate. Capital costs for rooftop systems may range between approximately $5.50 and $7.00 per Watt, while carport systems may range between approximately $4.50 and $7.00 per Watt. Capital costs may vary depending on the ease of installation, system size, technology choice, and labor costs; rooftop systems in particular can significantly range in costs due to potential constraints of a particular roof. Black & Veatch considers the estimated costs of O&M ($0.0010/kWh) to be much less than what is expected for rooftop systems in Northern California.

The 2001 Report describes O&M costs to be negligible. While O&M costs are a small part of a project's economics, the value presented in the 2001 Report under represents the expected costs seen today. See Table 3-4 for updated assumptions for Capital and O&M Costs.

Table 3-4 Capital and O&M Cost Update

COST	2001 REPORT	2012 UPDATED*
Rooftop Installed Capital Cost - $/W	$9.07	$5.50 - $7.00
Carport Installed Capital Cost - $/W	$9.18	$4.50 - $7.00
Annual Rooftop/Carport Operations & Maintenance (O&M) Estimated Cost - $/W**	$0.0019	$0.015-$0.030

*** Costs vary dependent on system size, mounting type, and other parameters.**
**** Typically, O&M costs are calculated on an annual cost per unit capacity basis (i.e. $/W annually), $/kW value for the 2001 report was calculated based on the system parameters presented in the report.**

3.2.3 Emissions Offset

The share of renewable generation in the California electricity mix has significantly increased since the 2001 report. The assumption made in the 2001 report under Section C, CEQA Considerations, that 1 kW of solar PV will offset 1 pound of Nitrogen oxides (NOx) and 4,520 pounds of Carbon Dioxide (CO2), is slightly outdated. The carbon dioxide emissions offset from solar PV installations has declined. The table below provides updated estimates to emissions offsets.

Table 3-5 Annual Emissions Offset by Solar PV in California

ANNUAL EMISSIONS OFFSET	2001 REPORT	2012 UPDATED*
Carbon Dioxide (CO_2) – lbs per kW installed	4,520.00	1,250.00
Nitrogen Oxides (NO_x) – lbs per kW installed	1	2.89
Carbon Dioxide (CO_2) – lb/MWh	-	658.68
Nitrogen Oxides (NO_x) – lb/MWh	-	0.42
Sulfur dioxide (SO_2) – lb/MWh	-	0.18

***Source: EPA eGRID 2012 Version 1.0, WECC California Grid**
The same system parameters as the 2001 Report were used to calculate annual lbs/kW emissions for the 2012 Updated values.

In 2011, PWRPA reported that the electricity delivered to SCVWD had created 54 pounds of CO_2e (Carbon Dioxide equivalent emissions[2]) emissions for every MWh delivered. If existing and proposed laws to cap carbon emissions are fully implemented and the market value of carbon and renewable energy credits increase and/or if PWRPA power rates increase beyond current levels, the cost-benefit of this project could become more favorable. The current value for carbon credits is approximately $10.71 per metric ton of CO2 and the current value of renewable energy credits are about $4 per MWh in 2013.

For comparative and educational purposes, the annual average estimated value of the power produced by this system, using a PG&E rate of $.15 per kWh is just under $50,000 per year. This is reasonably close to the estimates of $50,000-$70,000 savings made by SCVWD staff during the planning study phase of the project. The renewable, self generated power produced by the project is equivalent to an annual 174,000 – 441,000 lb reduction of CO2 when compared to power available from electric utilities. The 174,000 – 441,000 lb range is based on different kWh to CO2 conversion factors in use. Currently PG&E uses a factor of .524 lbs of CO2 per kWh, while the California average is .724 lbs per kWh and the U.S. average is set at 1.329 lbs per kWh. SCVWD's informational kiosks use a factor of 1.241 lbs per kWh in computing CO2 emissions. It was noted during this examination that during the planning phase of the project, the conversion factors in use at that time were significantly higher than the factors in use today.

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[2] Carbon Dioxide equivalent (CO2e) is a metric measurement of the emissions from various greenhouse gases that is based on their global warming potential.

4.0 Site Overview

SCVWD identified five sites to be investigated for solar PV feasibility. Black & Veatch has reviewed the climate, solar resource, and other attributes at each of the five sites related to development of a solar PV project (site topography, neighborhood, interconnection access, site access). This analysis is summarized in the sections below. This analysis assumes that the interconnection facilities have the appropriate available capacity.

These sites are listed in the table below. Sites 1, 2, and 3 are unused, open plots of land. Site 4 (PWTP) is an open ground area at SCVWD's Penitencia Water Treatment Plant, and Site 5 (STWTP) includes two open ground areas and two water basins at SCVWD's Santa Teresa Water Treatment Plant.

Table 4-1 Summary of Project Locations

Site Name	Latitude/ Longitude	Address	Closest Population Center	Acres of available space
Site 1	37.34°/-121.78°	2321-2341 Klein Rd, San Jose, CA 95148	San Jose	10.8
Site 2	37.19°/-121.69°	Coyote Creek Golf Dr & U.S. 101 San Jose, CA 95037	Morgan Hill	17.7
Site 3	37.11°/-121.61°	956-1028 Maple Ave Morgan Hill, CA 95037	Morgan Hill	15.3
Site 4: PWTP	37.40°/-121.83°	3959 Whitman Way, San Jose, CA 95132	San Jose	0.7
Site 5: STWTP	37.22°/-121.84°	7011 Graystone Lane, San Jose, CA 10120	San Jose	2.6

The general locations of the sites relative to each other are illustrated in Figure 4-1 below.

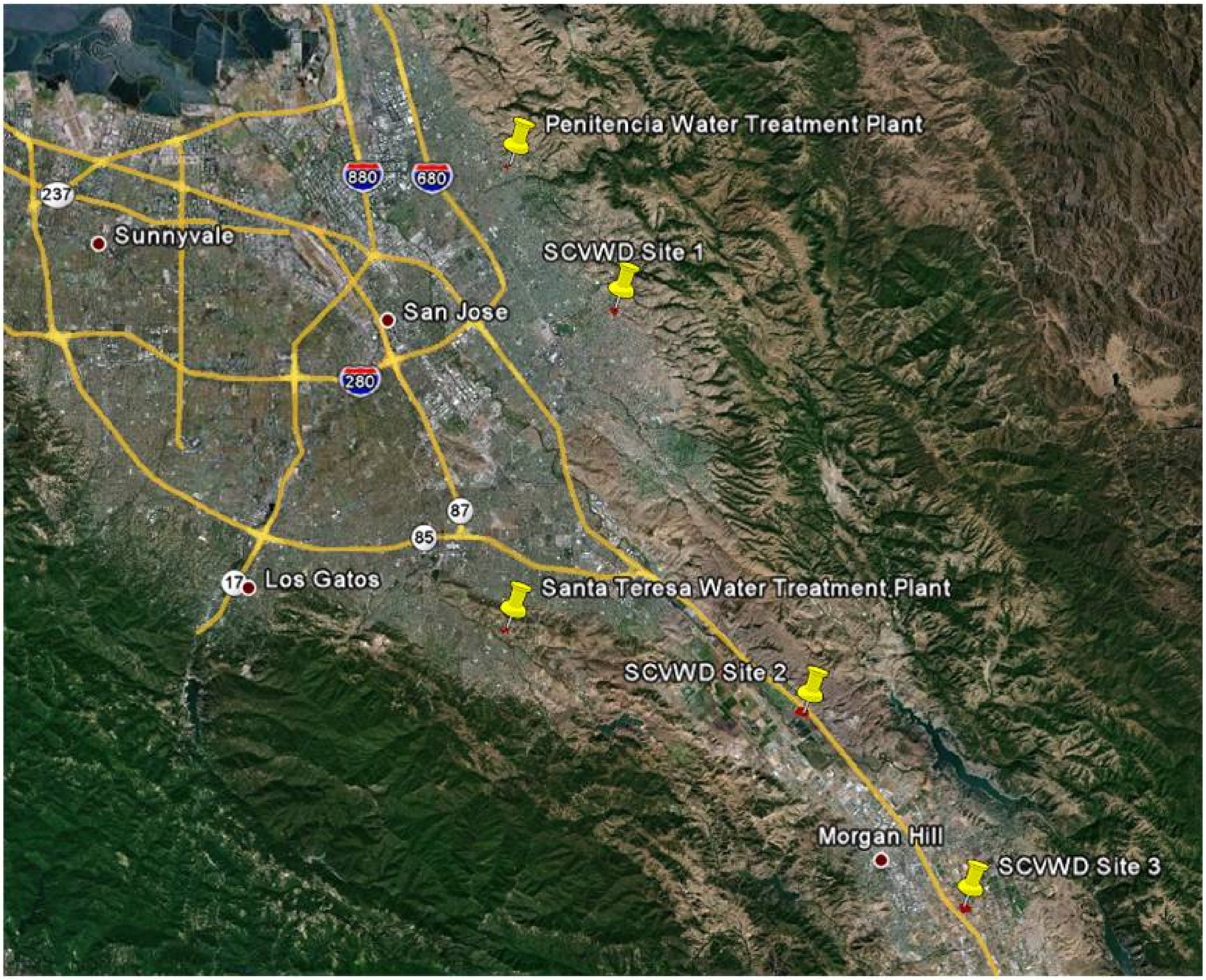

Figure 4-1 **SCVWD Solar PV Site Locations**

4.1 CLIMATE

Climate is an important aspect of site development and energy production modeling since climatic factors directly impact site conditions and energy production. Solar cells become less efficient at high temperatures, while heavy rainfall can increase production by washing accumulated soil from the modules.

The sites typically have hot summers with little rain, while the winters are typically cool and mild with moderate rainfall. Table 4-2, Figure 4-2, and Figure 4-3 summarize the typical weather conditions at the sites.

Table 4-2 Summary of Weather Conditions

Site	Average Annual (°F)	Average Summer Highs (°F)	Average Winter Lows (°F)	Average Annual Rainfall (in)	Average Annual Snowfall (in)
San Jose *	59.8	81.0	41.0	14.6	0

*** Weather data for Morgan Hill is not available. San Jose is considered an adequate representation of the Morgan Hill area.**

Source: Weatherbase.com, 2012.

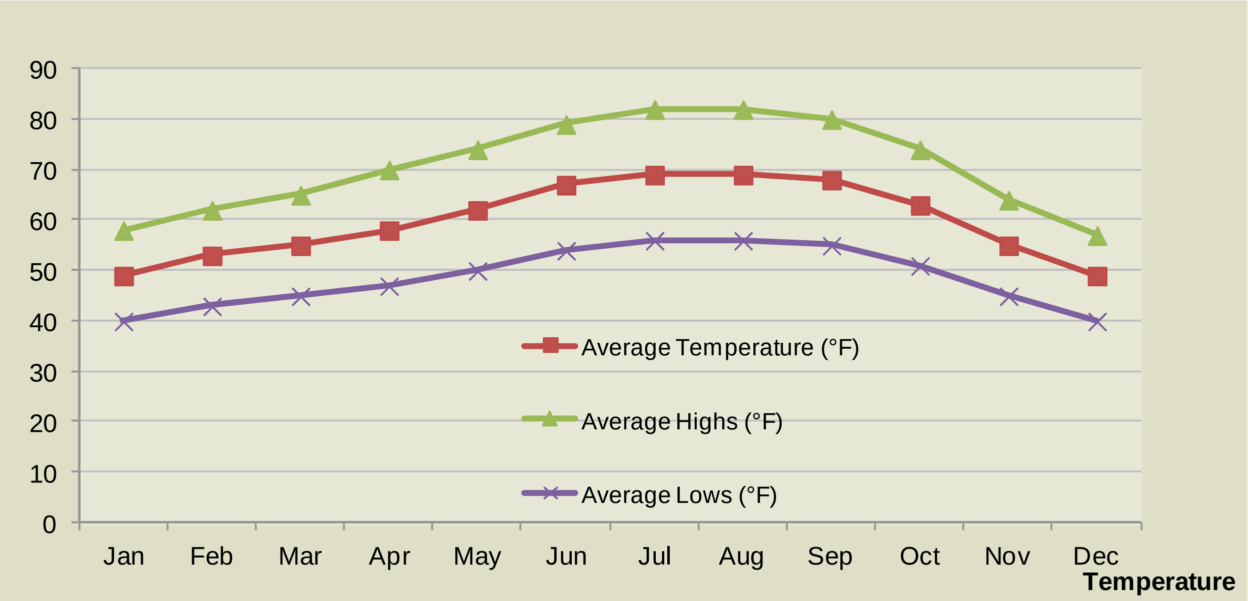

Figure 4-2 Average Monthly Temperatures for San Jose, CA (Source: Weatherbase.com)

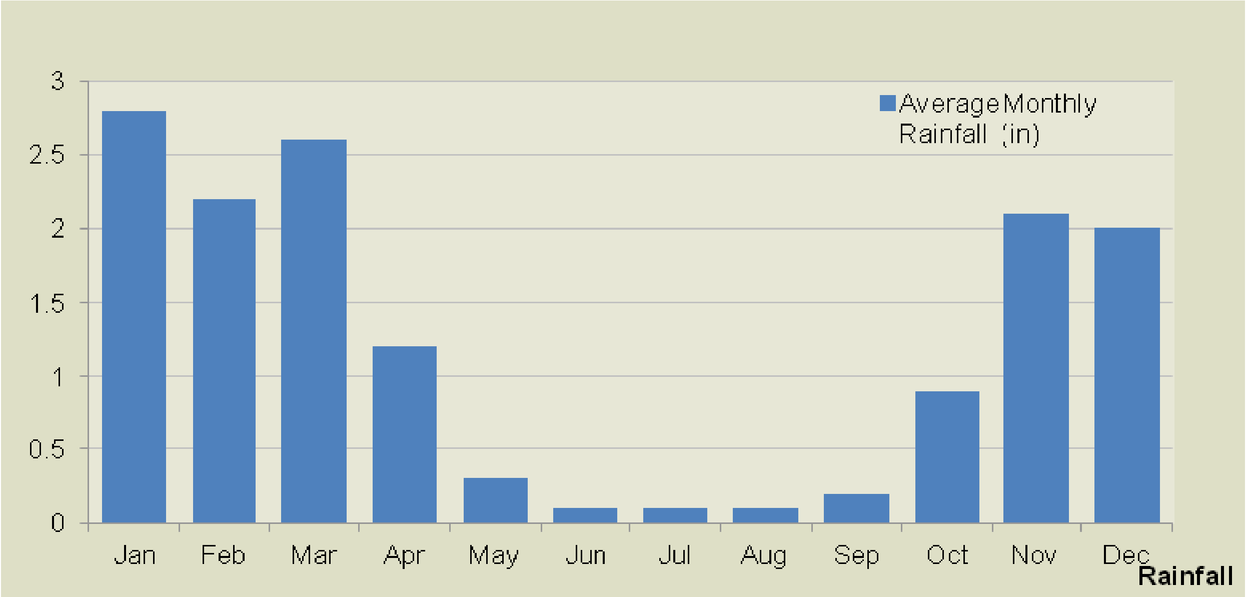

Figure 4-3 **Average Monthly Rainfall for San Jose, CA (Source: Weatherbase.com)**

The low amount of average rainfall in the summer months may result in increased module soiling that will reduce the power output of the solar PV systems. An estimated soiling loss of 3 percent annual losses was assumed for the preliminary production estimates found in the Section 6.0.

4.2 SOLAR RESOURCE

This section assesses various sources for solar resource data that are applicable for each site. The most suitable dataset is identified for each site.

4.2.1 Datasets

Black & Veatch assessed several solar resource datasets from various databases to determine which dataset is most representative of the conditions at each site. These datasets are described in the following table.

Table 4-3 Solar Resource Methodology

DATA SOURCE	METHODOLOGY DESCRIPTION	DESCRIPTION	YEARS	UNCERTAINTY GLOBAL HORIZONTAL *
TMY2	Modeled from observed climate, measured data	The National Renewable Energy Laboratory (NREL) first released Typical Meteorological Year files (TMYs) based on data from 1948 – 1980, but the data was of poor quality and its use has been discontinued. NREL's second release of TMYs is the TMY2 dataset, which is an updated version from the first release and based on more recent data. TMY2 data is available for 239 stations; the dataset is derived from 30 years of modeled data.	1961-1990	5 %
TGY	Modeled from satellite observed cloud cover, Perez model.	NREL worked with the State University of New York (SUNY) and Dr. Richard Perez to derive solar resource data from satellite imagery. This data is often referred to as the SUNY-Perez dataset. The data can be obtained from a tool called Solar Power Prospector on a 10 by 10 kilometer grid across the United States and parts of Canada. NREL has compiled this data into Typical Global Horizontal Insolation Years (TGY) for use in energy modeling.	1998-2009	5 – 10 %
TMY3	Modeled from celiometer data, SUNY-Perez satellite data, measured data	The third release of TMY's is the TMY3 dataset. TMY3 data is based on ground and satellite measurements, but the dataset has several inconsistencies. From 1991 to 1997, ceilometers were used to measure cloud cover, while from 1998 to 2005 satellite-based measurements of cloud cover were implemented. This compilation of different measurement techniques into a single dataset causes TMY3 data to often be of inconsistent quality.	1953-2005	5-10 %

Notes:

*** Uncertainty is a single standard deviation expressed as a percentage of the long term mean annual insolation. Uncertainty is also determined by the accuracy of the measurement instruments used to collect data on GHI.**

4.2.2 Solar Resource Analysis

Black & Veatch compared the applicable solar resource datasets for each site. The figure below illustrates geographically where each dataset is located in relation to the site. The yellow pins represent the project locations. The red sun represent San Francisco International Airport (SFO) TMY2 station. The San Jose International Airport TMY3 station is represented by a purple circle. The other two purple circles represent TMY3 stations that are not considered in this analysis. The TGY data is not shown on the map below, but is available throughout the U.S. on a 10 km by 10 km grid.

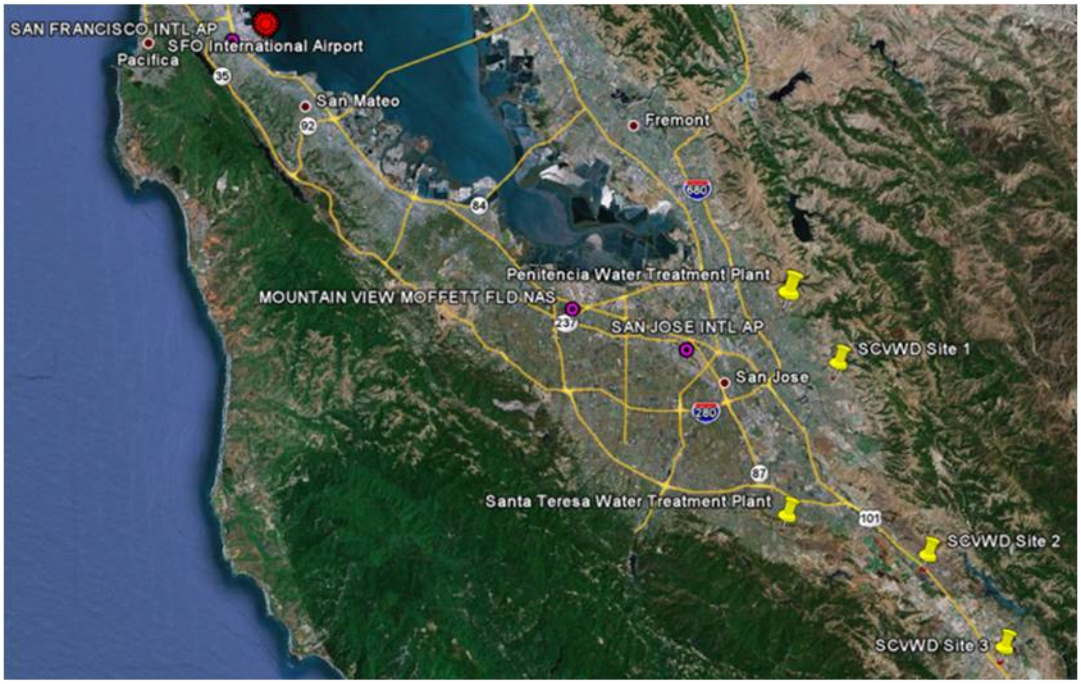

Figure 4-4 Applicable Datasets near sites (Source: Google Earth, accessed Oct. 2012)

Table 4-4 below summarizes parameters for each dataset. The distance between the site and solar resource stations are included, as well as the typical annual global horizontal insolation (GHI). The datasets considered most adequate to represent the solar resource at each site are shown in bold and italics. Due to the historical depth and quality of TMY2 data, Black & Veatch considers TMY2 to be the best available solar resource dataset. When sites are in close proximity to a TMY2 site, it is Black & Veatch's preference to utilize this dataset to forecast production from PV power plants. Due to the distance of the sites from the SFO TMY2 station, and the differences in climate and weather patterns experienced between the sites and SFO, the TGY datasets were chosen because of their proximity to the site and quality of data.

Table 4-4 Solar Resource Sources

Location	Latitude	Longitude	Source	Distance to Site (mi)	Typical Annual GHI (kWh/m2)
SFO	37.62	-122.37	TMY2	34-55	1,738
San Jose Intl. Airport	37.37	-121.93	TMY3	6-25	1,810
Site 1	***37.34***	***-121.78***	***TGY***	***0***	***1,896***
Sites 2 and 3	***37.19***	***-121.69***	***TGY***	***0***	***1,894***
Site 4: PWTP	***37.40***	***-121.83***	***TGY***	***0***	***1,877***
Site 5: STWTP	***37.22***	***-121.84***	***TGY***	***0***	***1,896***

Notes:
The datasets chosen for this analysis is in bold *italics*.

4.3 SITE 1

Site 1, outlined in red in Figure 4-5 below, consists of 10.8 acres of available land that slopes slightly to the southwest and is primarily grass land. This land was acquired in 1978 for a district East Reservoir project which was not constructed since alternative facilities replaced the project needs. A district proposed weather station project was in progress on 3.8 acres of this property, which was cancelled at a later time. The land is available for lease for dry hay farming. There is approximately 40 feet of elevation drop between the highest point in the north part of the site and the lowest point in the south part of the site. The site does not have any large structures or trees that would need to be removed prior to construction, therefore the site ground prep-work required will likely be minimal. Black & Veatch notes that the southward slope of the land is advantageous to a solar PV project.

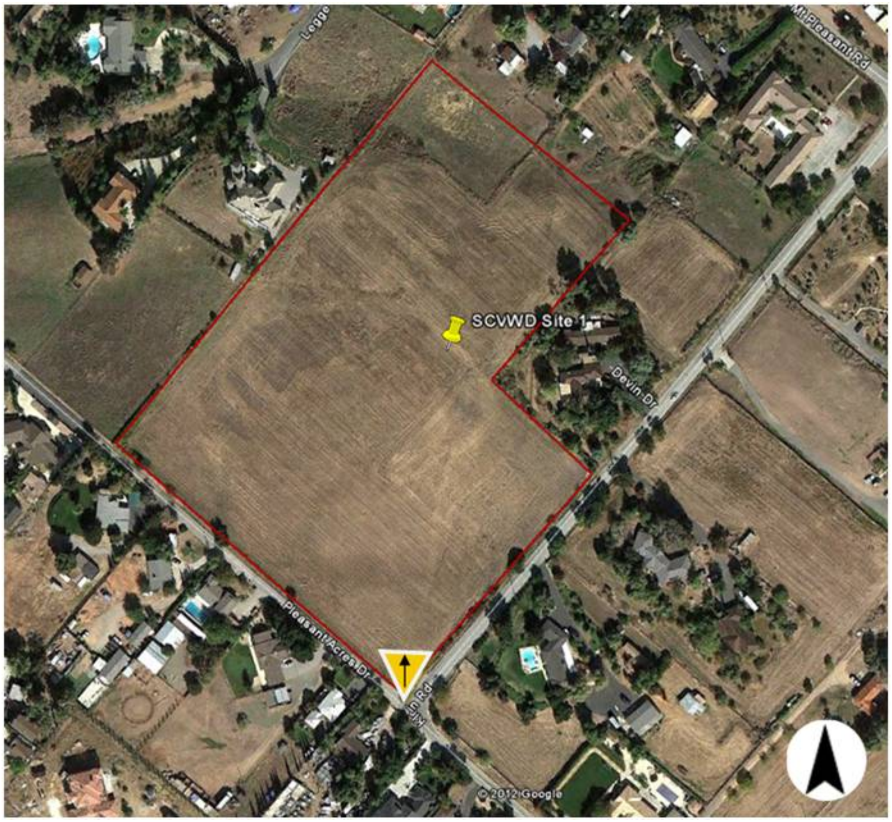

Figure 4-5 Site 1 Location

The site is located approximately 6 miles east of downtown San Jose, along Pleasant Acres Drive and Klein Road in a residential neighborhood. There are four residential properties that border the site:

- 2316 Legge Court (West of site)
- 2316 Mt. Pleasant Road (North of site)
- 2322 Mt. Pleasant Road (North of site)

- 3709 Klein Road (East of site)

Black & Veatch recommends that a community outreach and informational session be conducted with homeowners in the area to ensure that all questions and concerns are addressed about a solar PV construction project taking place on this site. Considerations should be made to assess the impact on the community in regards to noise and glare originating from the solar PV system. A solar PV installation would have to be approved by local permitting authorities, but it is expected that there should not be any significant permitting issues.

The roads that provide access to the site are narrow and may present some challenges for large trucks and heavy equipment during the procurement and construction process. Special permits and permissions may be needed in order for construction vehicles to pass through the residential neighborhood surrounding the site.

Because the site is adjacent to residential property, it is assumed that a PG&E distribution line is accessible for interconnection of a solar PV facility.

The site as viewed from the ground is shown in Figure 4-6, with the point-of-view depicted in Figure 4-5 as a yellow triangle and arrow.

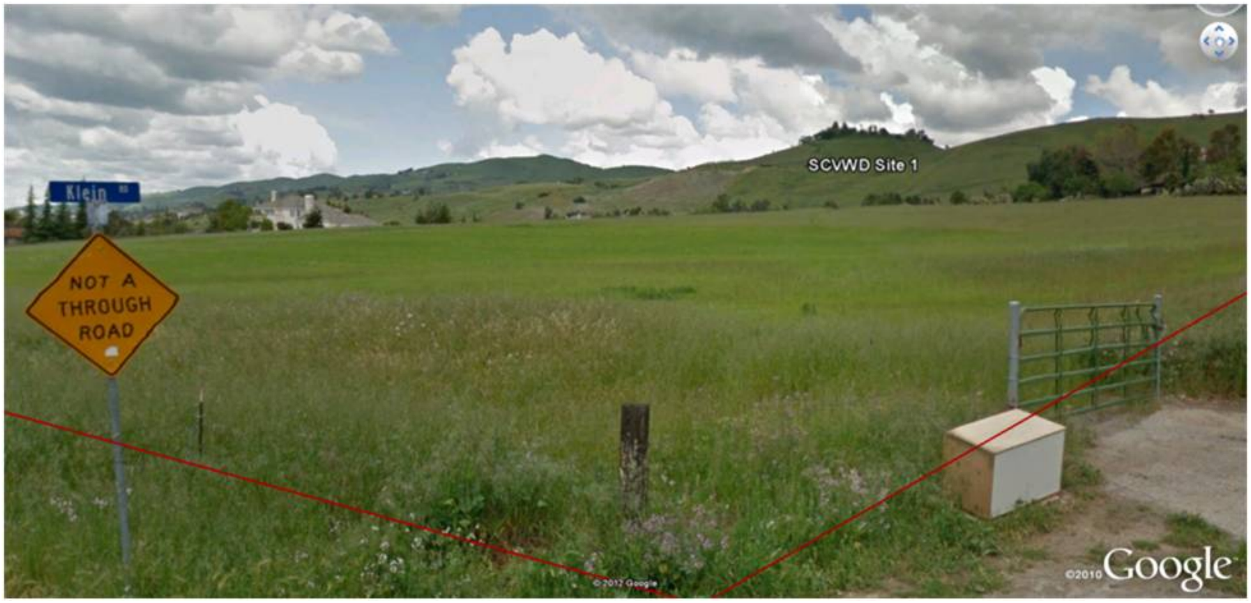

Figure 4-6 Ground View of Site 1

4.4 SITE 2

Site 2, outlined in red, on Figure 4-7 below, consists of 17.7 acres of available land that slopes very slightly to the south and is primarily grass land with a few small trees in the south east area of the site. There is approximately 15 feet of elevation drop between the highest point in the north part of the site and the lowest point in the south part of the site. The site is not located in a residential neighborhood and is primarily surrounded by grassland and US 101. A solar PV installation would have to be approved by local permitting authorities, but it is expected that there should not be any significant permitting issues. There appears to be some type of facility (possibly a natural gas pipeline) entering the site from the northwest corner of the site, near the US 101 onramp entrance. Identifying the facility's function and possible impacts to surrounding solar PV development was not within the scope of this feasibility study.

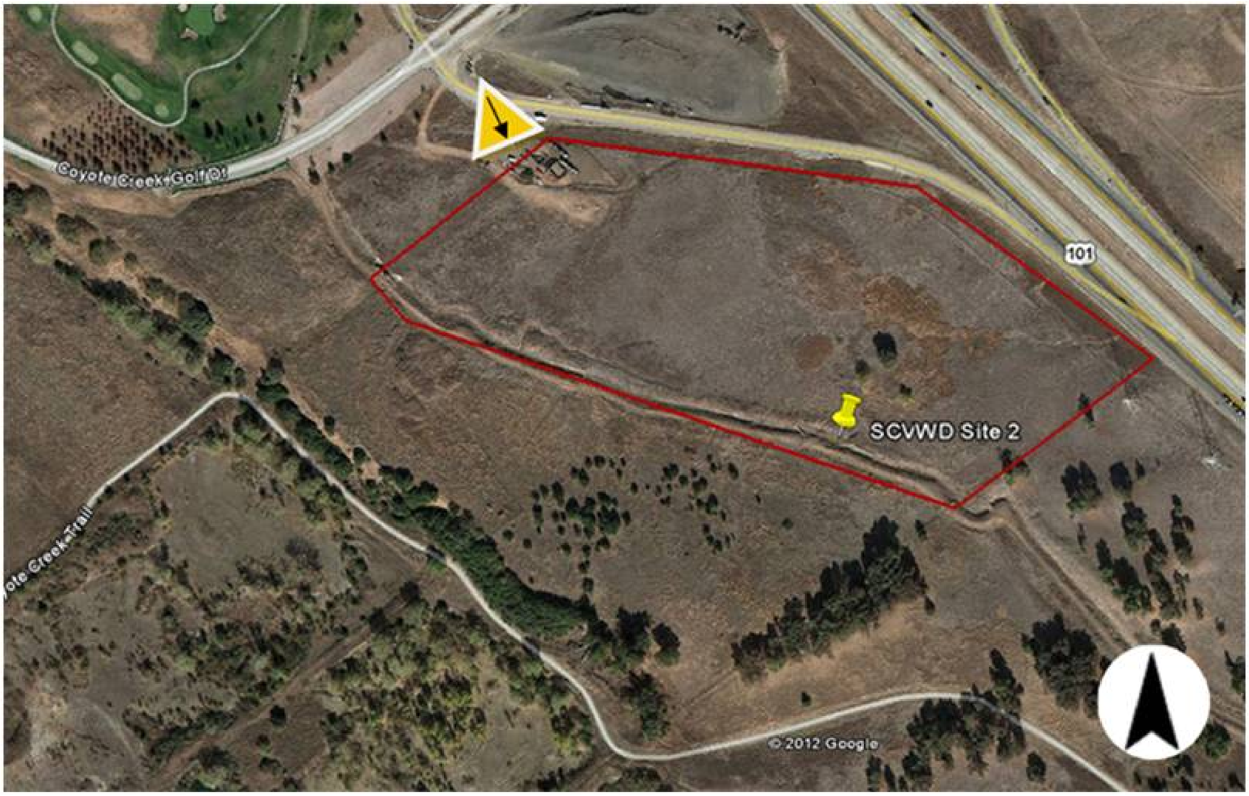

Figure 4-7 Site 2 Location

The site is located approximately 15 miles southeast of downtown San Jose and 5 miles northwest of Morgan Hill along Coyote Creek Golf Drive and US 101. The site is accessible via Coyote Creek Golf Drive, which is likely not a heavily used road and should not present any major challenges to large trucks and heavy machinery travelling to the site. This property was acquired in 1936 for Coyote Canal and a portion is currently used for the canal and remaining portions may be needed in the future.

The site is adjacent to transmission lines and within a mile of industrial and residential facilities. It is assumed that a PG&E line is accessible for interconnection. The site as viewed from the ground is shown in Figure 4-8, with the point-of-view depicted in Figure 4-7 as a yellow triangle and arrow.

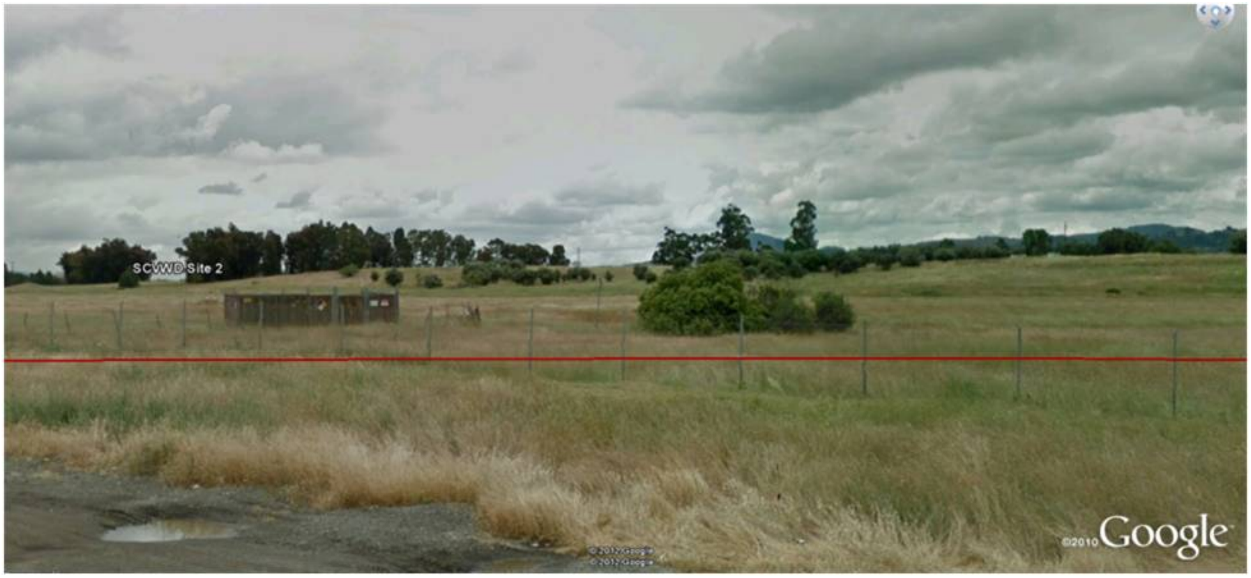

Figure 4-8 Ground View of Site 2

There is a small fenced-in section on the property, shown on the left side of Figure 4-8 that is part of the facilities entering the site. The area directly around this section is not useable for solar PV development.

4.5 SITE 3

Site 3, outlined in red in Figure 4-9 below, consists of 15.3 acres of generally flat land and is primarily grassland with an area of small trees in the eastern most section of the site. This property was acquired in 1984 for Maple Avenue Percolation Pond project that was cancelled due to soil conditions. The land is available for future project use.

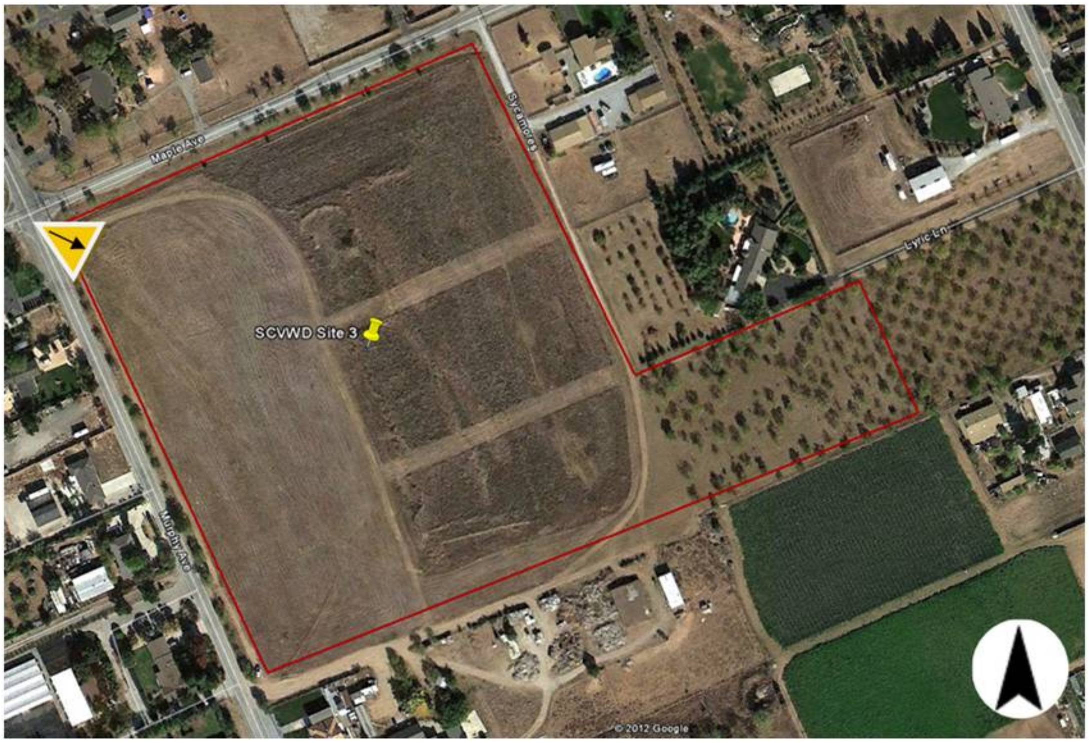

Figure 4-9 Site 3 Location

The site is located approximately 22 miles southeast of downtown San Jose and 2.5 miles southeast of Morgan Hill, along Maple Avenue and Murphy Avenue in a residential neighborhood. There are three residential properties that border the site:

- 980 Maple Ave (North East of site)
- 15265 Sycamore Ave (East of site)
- 15110 Murphy Ave (South of site)

There are many more homes across from Maple and Murphy Avenues that would be affected by solar PV construction on this land. Black & Veatch recommends that a community outreach and informational session be conducted with homeowners in the area to ensure that all questions and concerns are addressed about a solar PV construction project taking place on this site. As with Site 1 and 2, considerations should be made to assess the impact on the community in regards to noise and glare originating from the solar PV system. A solar PV installation would have to be approved by local permitting authorities, but it is expected that there should not be any significant permitting issues.

The site is primarily accessible via Murphy Avenue, which can be accessed from Tennant Avenue and is in close proximity to US 101. The roads to the site should not present any major challenges to large trucks and heavy machinery travelling to the site.

As mentioned above, the site is adjacent to residential property. It is expected that a PG&E distribution line will be within the vicinity of the site.

The site as viewed from the ground is shown in Figure 4-10, with the point-of-view depicted in Figure 4-9 as a yellow triangle and arrow.

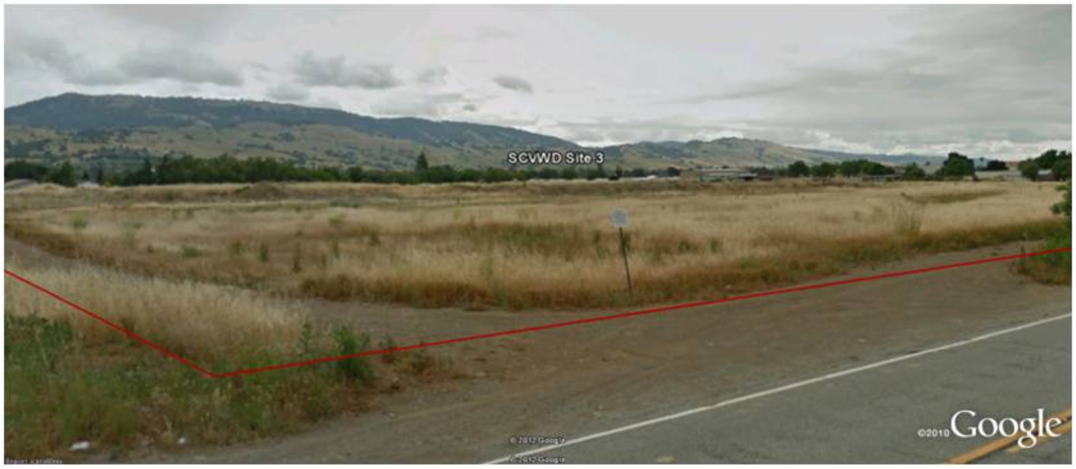

Figure 4-10 Ground View of Site 3

4.6 SITE 4: PENITENCIA WATER TREATMENT PLANT

The Penitencia Water Treatment Plant (PWTP) Site 4, outlined in red, on Figure 4-7 below, consists of 0.7 acres of available land that slopes slightly to the southwest and is primarily grass with a few small trees along the northeast edge of the area. There is approximately 10 feet of elevation drop between the highest point in the northeast part of the site and the lowest point in the southwest part of the site.

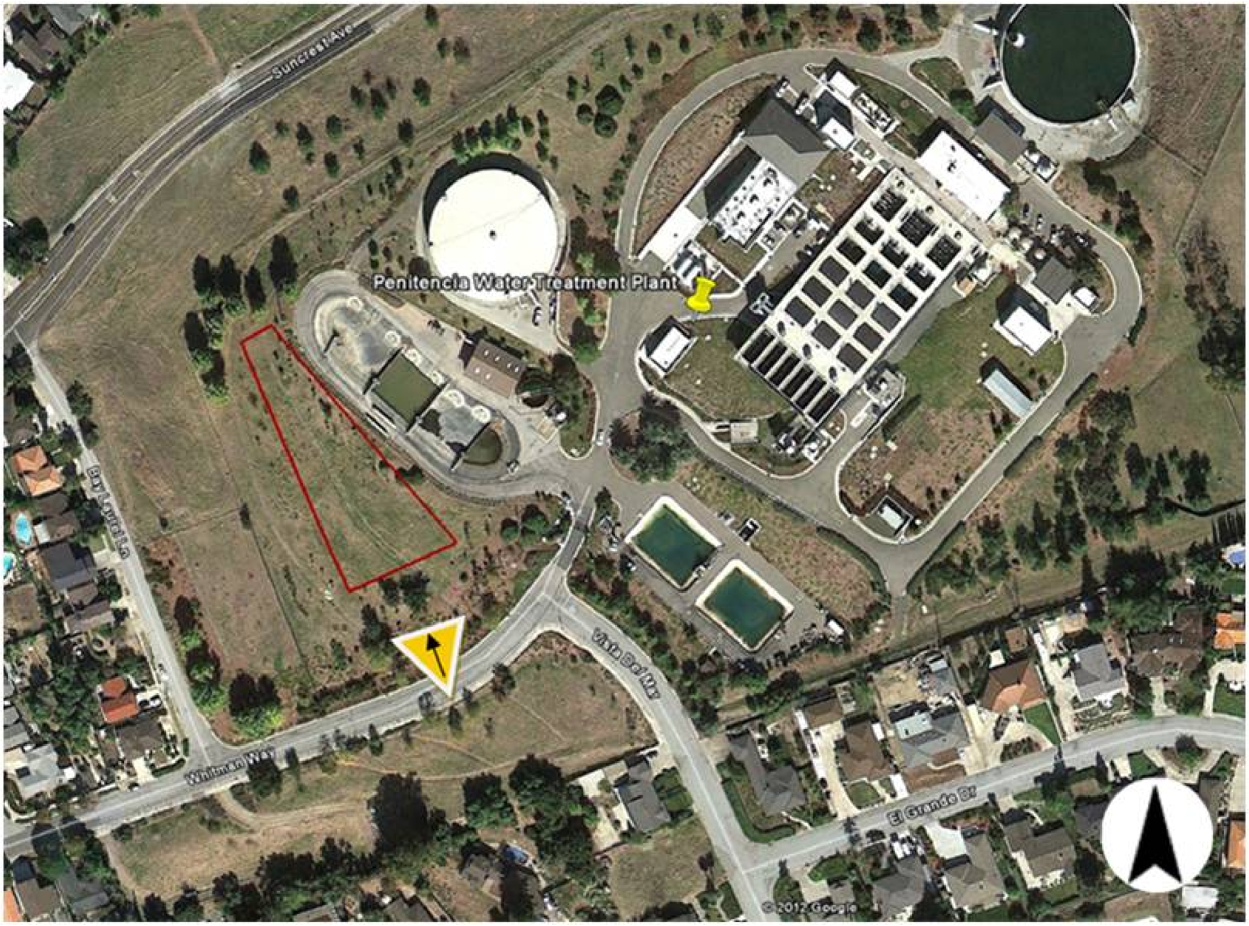

Figure 4-11 Site 4 (PWTP) Location

The site is located approximately 6 miles northeast of downtown San Jose along Vista Del Mar and Whitman Way. The site is located near a residential neighborhood but is primarily surrounded by the treatment plant structure(s), trees and grassland. Black & Veatch recommends that a community outreach and informational session be conducted with homeowners in the area to ensure that all questions and concerns are addressed about a solar PV construction project taking place on this site. Considerations should be made to assess the impact on the community in regards to noise and glare originating from the solar PV system.

The site is accessible via Whitman Way, which can be accessed from Piedmont Road and in close proximity to Interstate 680. The roads to the site should not present any major challenges to large trucks and heavy machinery travelling to the site.

It is assumed at the solar PV system will interconnect locally into the PWTP's electrical infrastructure. The site as viewed from the ground is shown in Figure 4-12, with the point-of-view depicted in Figure 4-11 as a yellow triangle and arrow.

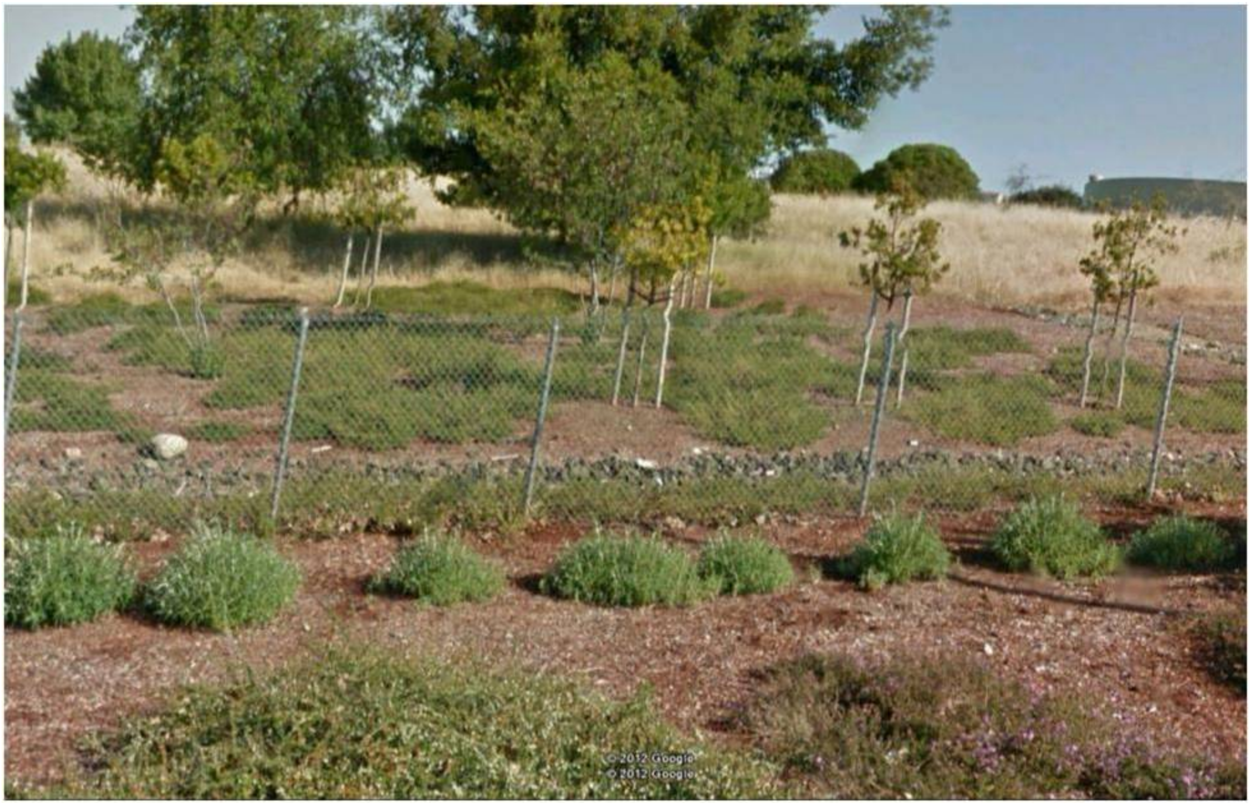

Figure 4-12 Ground View of Site 4

There do not appear to be any obstacles or major challenges facing solar PV development on this site.

4.7 SITE 5: SANTA TERESA WATER TREATMENT PLANT

The Santa Teresa Water Treatment Plant (STWTP) Site 5, outlined in red in Figure 4-13 below, consists of 2.6 acres of available open land and roof space above sedimentation basins. For the two sites on open land there is approximately 10 feet of elevation drop between the highest point in the north part of the areas and the lowest point in the south part of the areas.

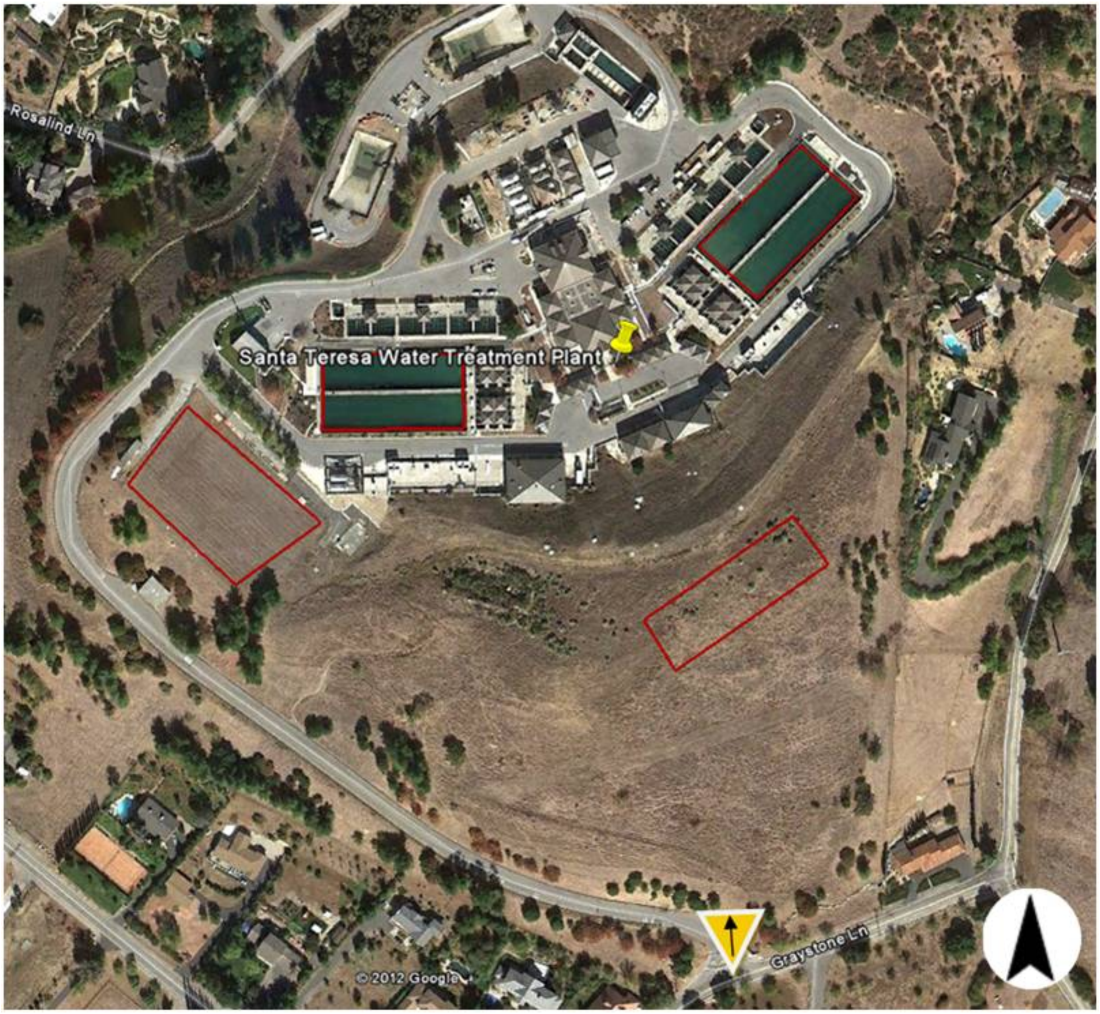

Figure 4-13 Site 5 (STWTP) Site Location

The site is located approximately 9 miles South East of downtown San Jose along Graystone Lane. The site is located near a residential neighborhood but is primarily surrounded by the treatment plant structure(s), trees and grassland. There are no residential homes in close proximity to the proposed sites; however, Black & Veatch recommends that a community outreach and informational session be conducted with homeowners in the area to ensure that all questions and concerns about a solar PV construction project taking place on this site are addressed.

Considerations should be made to assess the impact on the community in regards to noise and glare originating from the solar PV system.

The site is accessible via Graystone Lane, which can be accessed from the Almaden Expressway. The road to the site should not present any major challenges to large trucks and heavy machinery travelling to the site.

It is assumed that the solar PV system will interconnect locally into the STWTP's electrical infrastructure. The site as viewed from the ground is shown in Figure 4-14, with the point-of-view depicted in Figure 4-13 as a yellow triangle and arrow.

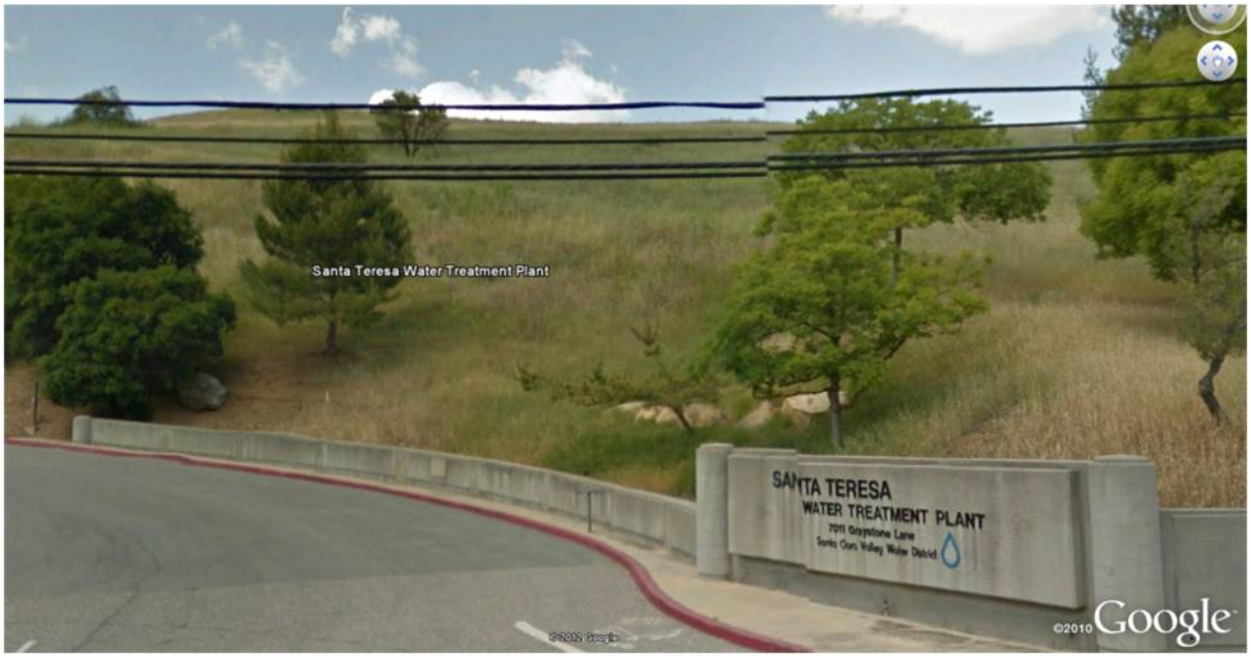

Figure 4-14 Ground View of Site 5

There is not a significant amount of trees surrounding the proposed ground-mount locations; however there are some trees that may shade modules located in the southern portion of the eastern most area. The two locations on sedimentation basins appear to require some pre-work to make the sites suitable for roof-top installation of a solar PV system.

5.0 Technical Potential

Black & Veatch assessed the technical potential of installing solar the potential capacity at the five proposed sites. The proposed development consists of fixed ground-mounted PV systems at five sites identified by the SCVWD located in Santa Clara County, California. For each of the conceptual layouts shown in the sections below, Black & Veatch assumes the land parcels will be graded to be suitable enough for a fixed-tilt racking system.

Black & Veatch made several design assumptions to estimate the kW capacity of each site. These are typical design parameters for projects of this size and include the following:

- Modules – Trina solar modules were assumed for this analysis. These modules represent a typical polycrystalline module widely used in many large commercial and utility-scale PV plants. Trina solar polycrystalline modules were assumed for this analysis as they are the most prevalent today and are considered Tier 1 module suppliers. The performance of these modules is expected to be adequate at the project site.
- Inverters – SMA and Emerson inverters were assumed for this analysis. These inverters represent typical performance of inverters available on the market today.
- Mounting type – a fixed-tilt system was chosen over a single-axis tracking system. Because the sites are space constrained, a fixed-tilt design allows for more capacity, and likely more energy production.
- Clear row spacing – designed using standard industry practices to mitigate row-to-row shading between the hours of 9 am and 3 pm all year.
- Tilt angle – a value of 25 degrees was chosen as this is a typical value used to balance between optimized energy production, and structural costs.
- Azimuth – a zero degree azimuth was assumed for all sites except Site 5 (STWTP). This is because the performance is expected to be optimized with this azimuth. Site 5 capacity would be limited to an off-zero azimuth do to the land and rooftop orientation available at the site.

Black & Veatch notes that after the site selection is narrowed, a detailed analysis would need to be performed in order to identify the optimal azimuth and system design. A slightly west-facing azimuth may benefit the financial viability of the systems given time-of-day (TOD) rates which value midday and afternoon production more than other times. For this analysis using a zero degree azimuth allows a proper comparison between sites.

A summary of potential system sizes and available land for PV development is presented in Table 5-1.

Table 5-1 Overall Site Summary

NAME	DESCRIPTION	TOTAL AVAILABLE AREA (ACRES*)	CAPACITY (kWp) **	CAPACITY (kW AC)
Site 1	Fixed Ground-Mount PV Site 1	10.8	2,938	2,520
Site 2	Fixed Ground-Mount PV Site 2	17.7	4,496	3,700
Site 3	Fixed Ground-Mount PV Site 3	15.3	3,906	3,200
Site 4	Penitencia Water Treatment Plant Fixed Ground-Mount PV	0.7	165	146
Site 5	Santa Teresa Water Treatment Plant Fixed Ground-Mount PV	2.6	820	720

*** Area of PV modules, racking and clear row spacing.**
**** kWp refers to the kW peak (or the Standard Test Conditions (STC)dc rating of the system).**

5.1 SITE 1

Site 1 is suitable for a fixed-tilt solar PV system and was designed at a zero degree azimuth; 15 foot clear row spacing; 25 degree tilt angle; and will occupy approximately 10.8 acres of the available parcel. Black & Veatch notes that a single-axis tracking system would likely have limited benefit because of the land parcel's odd shape, the non-zero azimuth and the mechanical properties of the tracker itself. SCVWD does not have any facilities or loads at this site. Therefore a solar PV system would need to interconnect to a local grid. The conceptual layout for Site 1, utilizing the entire site, is shown below in Figure 5-1.

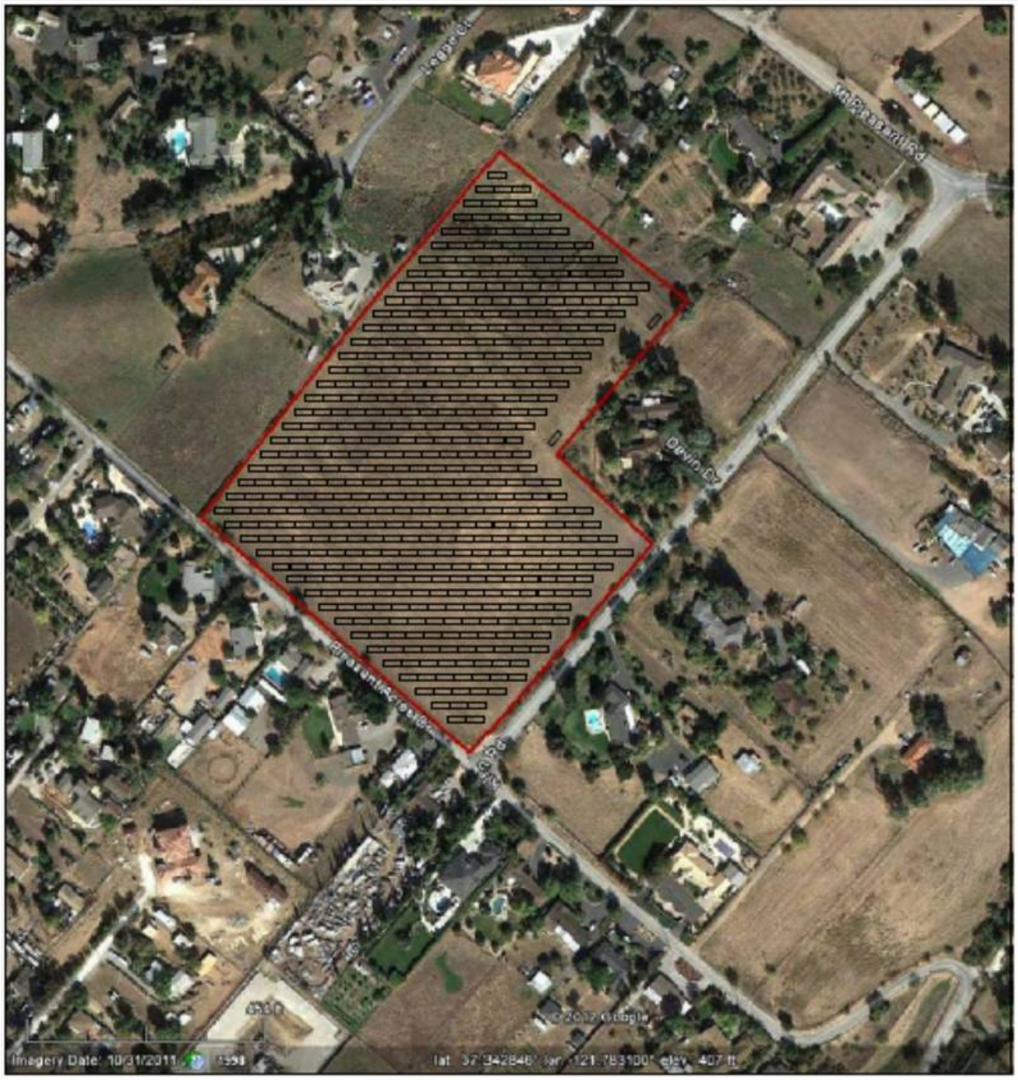

Figure 5-1 Site 1 Conceptual Layout

5.2 SITE 2

Site 2 is suitable for a fixed-tilt solar PV system and was designed at a zero degree azimuth, 15 foot clear row-spacing, 25 degree tilt angle, and will occupy approximately 17.7 acres of the available parcel. Black & Veatch notes that a single-axis tracking system would likely have limited benefit because of the land parcel's odd shape, the non-zero azimuth, and the mechanical properties of the tracker itself. Black & Veatch avoided placing any PV in the area surrounding the gas facilities/structure in the northwest area of the site. This area is likely a natural gas pipeline station/valve that will impact the overall site layout of a solar PV system. The extent of underground piping and the restrictions on land development will need to be assessed before a system is designed for this site. SCVWD does not have any facilities or loads at this site. Therefore, a solar PV system would need to interconnect to a local grid. The conceptual layout for Site 2, utilizing the entire site, is shown below in Figure 5-2.

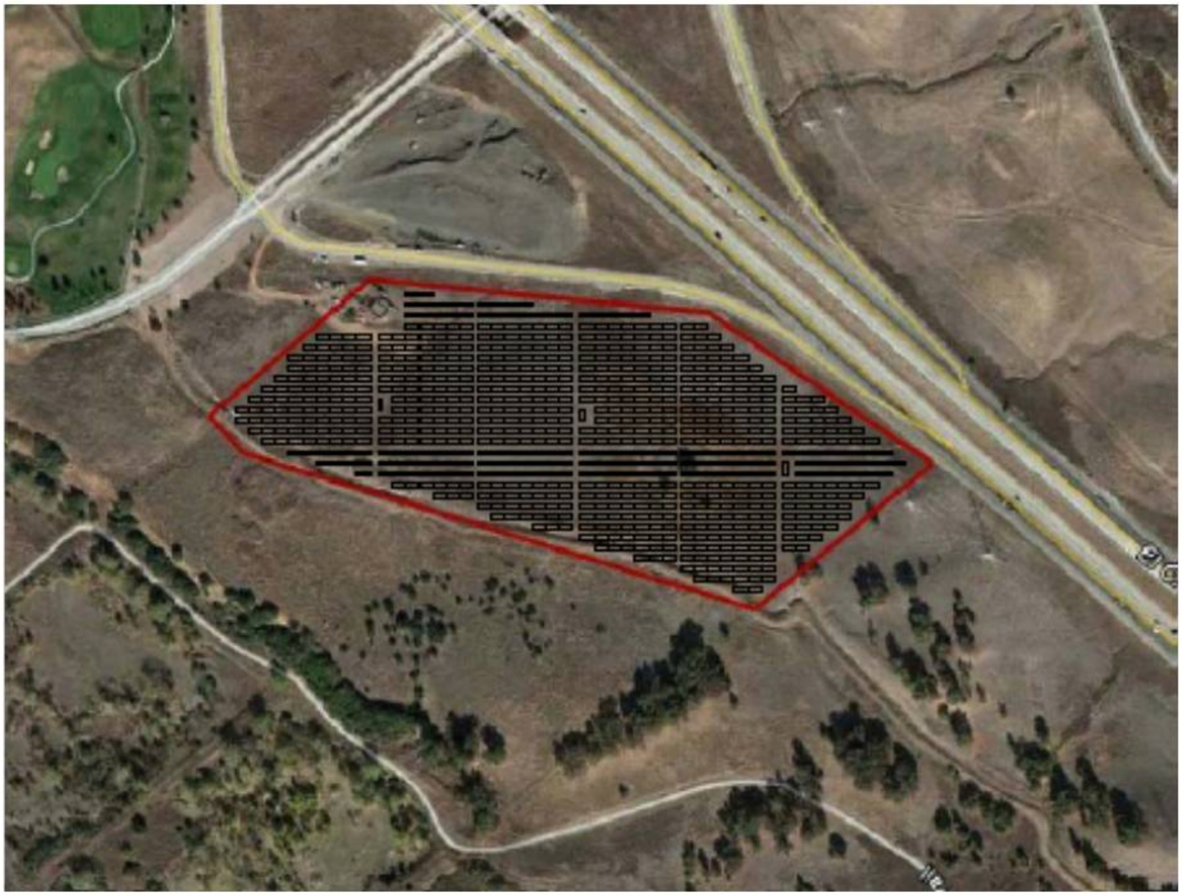

Figure 5-2 Site 2 Conceptual Layout

5.3 SITE 3

Site 3 is suitable for a fixed-tilt solar PV system and was designed at a zero degree azimuth, 15 foot clear row spacing, 25 degree tilt angle, and will occupy approximately 15.3 acres of the available parcel. Black & Veatch notes that a single-axis tracking system would likely have limited benefit because of the land parcel’s odd shape, the non-zero azimuth, and the mechanical properties of the tracker itself. SCVWD does not have any facilities or loads at this site. Therefore; a solar PV system would need to interconnect to a local grid. The conceptual layout for Site 3, utilizing the entire site, is shown below in Figure 5-3.

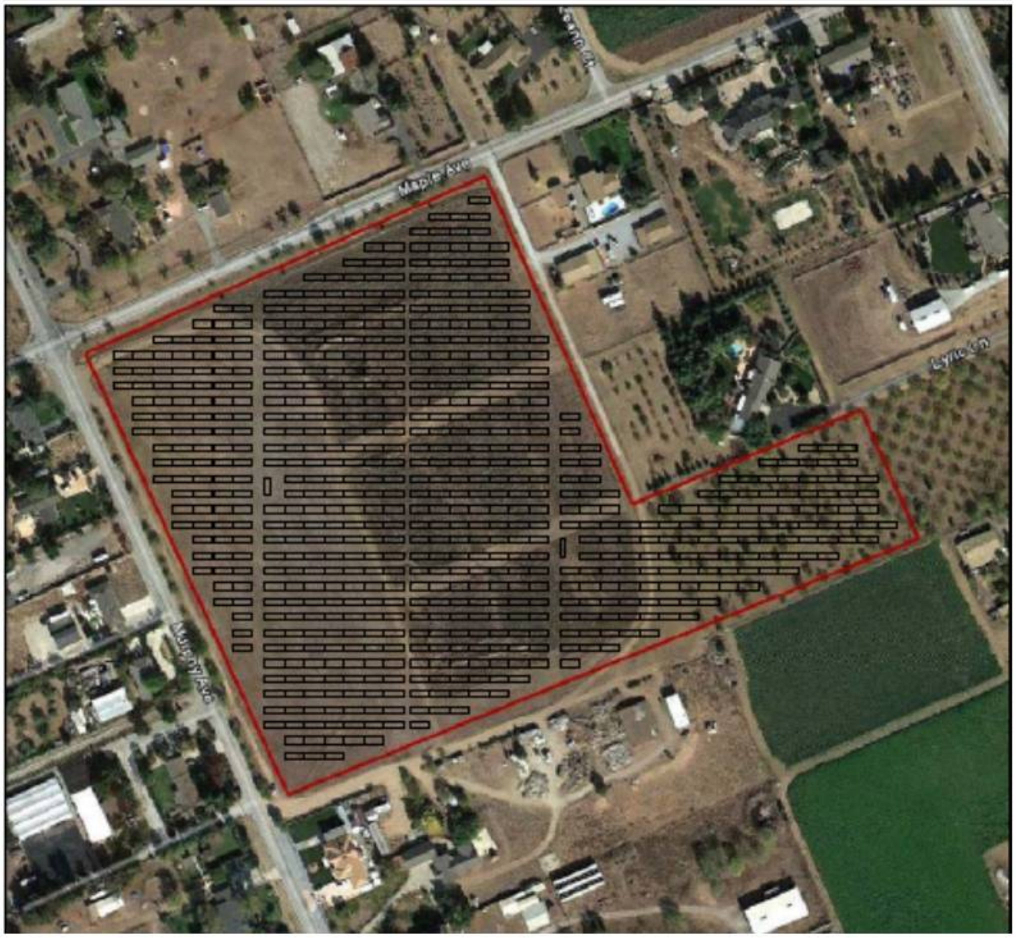

Figure 5-3 Site 3 Conceptual Layout

5.4 SITE 4: PENITENCIA WATER TREATMENT PLANT

Site 4 is a small parcel located on the southwest property of the PWTP. The PV array was designed at a zero degree azimuth, 15 foot clear row spacing, 25 degree fixed-tilt angle, and will occupy approximately 0.7 acres of the available parcel. The energy production of the solar PV facility is expected to partially offset the local load at PWTP. The conceptual layout for Penitencia Water Treatment Plant is shown below in Figure 5-4.

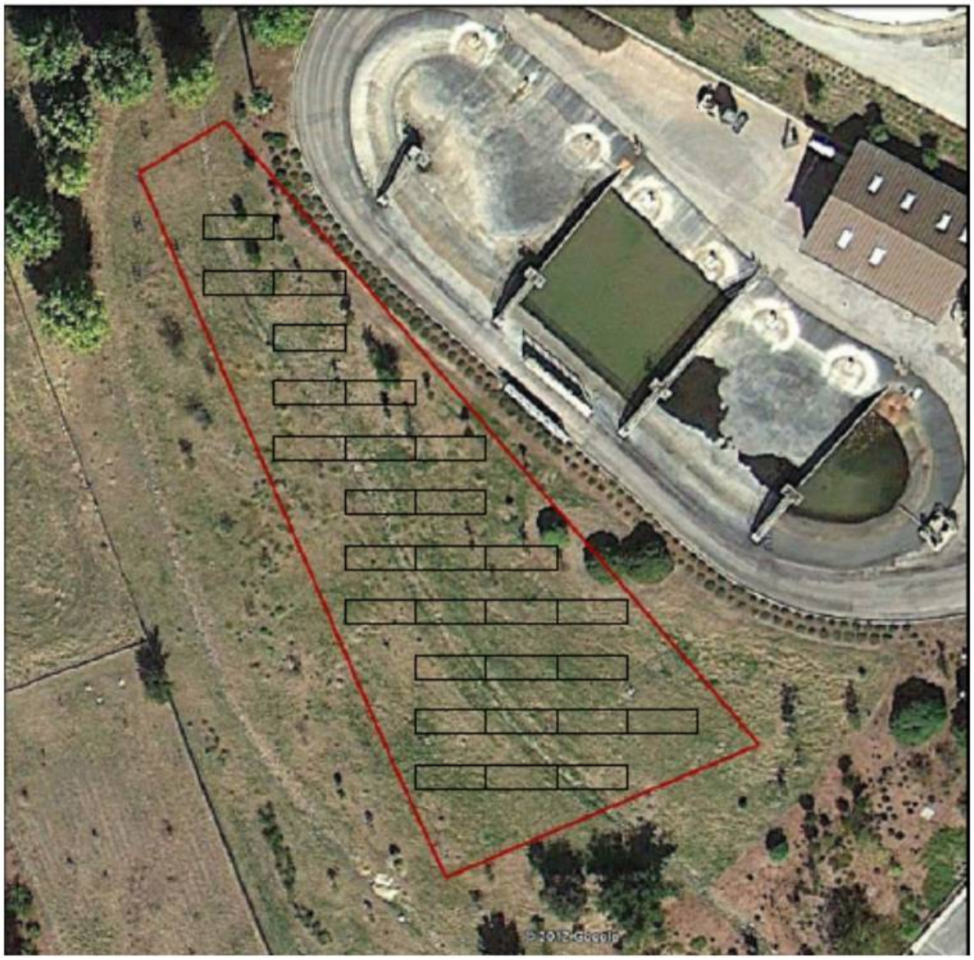

Figure 5-4 PWTP Conceptual Layout

5.5 SITE 5: SANTA TERESA WATER TREATMENT PLANT

The fifth and final site consists of four separate PV arrays located at the STWTP. Due to the very small parcel areas provided for each of the four arrays, the arrays follow the contours of the boundary, resulting in non-zero azimuth angles. Additionally, Black & Veatch assumes that the East and West basins will be emptied and/or filled to be suitable for construction for the PV arrays and foundations. The PV array located on the southwest side of the property will be oriented approximately 47 degrees to the east. The PV array located on the south side of the property will be oriented approximately 56 degrees to the west. The PV array located inside the East basin will be oriented approximately 45 degrees to the west. The PV array located inside the West basin will be oriented at a zero degree azimuth facing due south.

Despite the various azimuth orientations for each of the PV arrays, the 15 foot clear row-spacing and 25 degree tilt remains the same. The energy production of the solar PV facility is expected to partially offset the local load at STWTP. Extra energy generation is expected to be net-metered. Each of the four conceptual PV arrays at the Santa Teresa Water Treatment Plant are shown below in Figure 5-5.

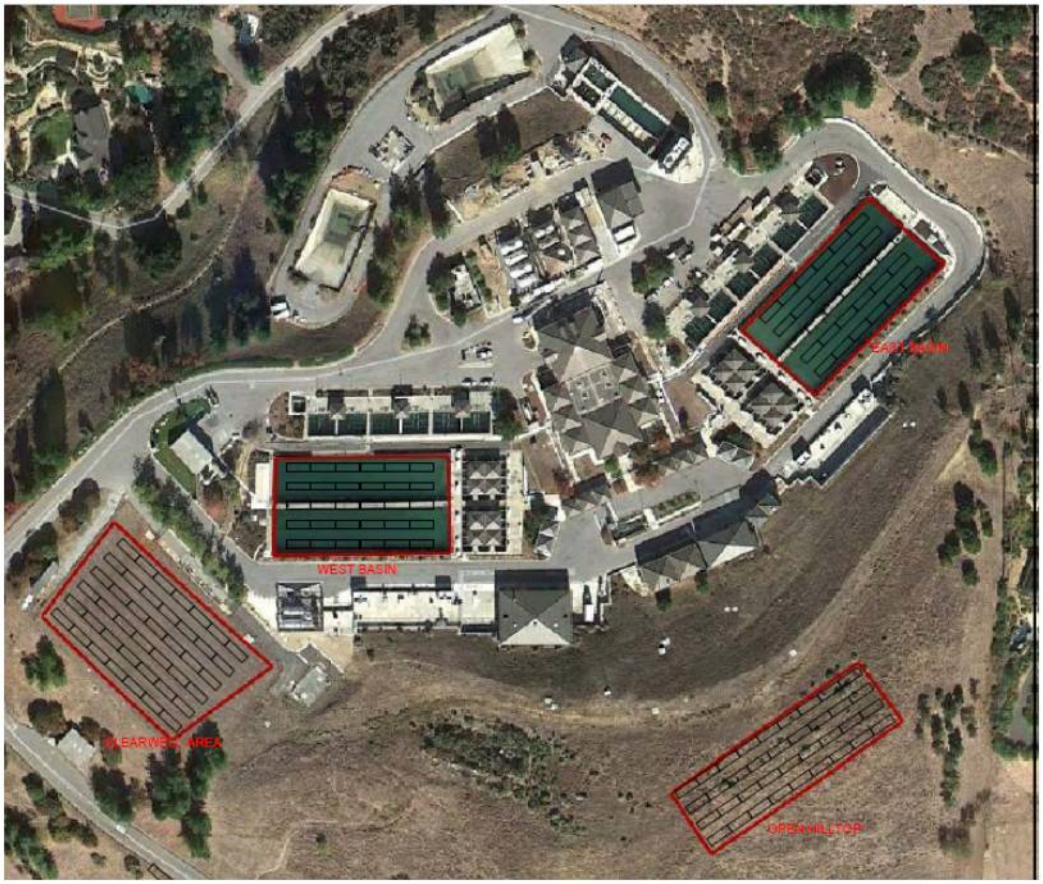

Figure 5-5 STWTP Conceptual Layout

6.0 Production Estimate Results

The energy production of the facilities described in section 5.0 is summarized in this section. The design parameters used for this analysis were chosen to represent typical system designs of this size. The estimated energy production of the five sites is summarized in the Table 6-1 below. The production values are net yields anticipated at the point of interconnection and include estimated annual losses (soiling, auxiliary loads, voltage drop, etc). The energy generation is described in MWh and is representative of generation expected during the first year of operation. Production during subsequent years is expected to degrade by 0.7 percent per year.

The DC[3] and AC[4] capacity factors represent the amount of time and at what capacity the system is producing energy. The annual yield represents how much energy is produced in a given year, per kW dc (kWp) installed. The performance ratio[5] represents the efficiency of the designed system. The numbers below are in line with typical performance for systems in the Santa Clara County area. The energy production can be further optimized by refining the system tilt, azimuth, and other design parameters.

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[3] DC Capacity Factor = First Year Generation (MWh) / [8,760 hours x System DC Capacity (MW)] x 100
[4] AC Capacity Factor = First Year Generation (MWh) / [8,760 hours x System AC Capacity (MW)] x 100
[5] Performance Ratio = First Year Generation (MWh) / (Solar Irradiance Incident on Panels (MWh)

Table 6-1 Production Estimate Results

SITE	FIRST YEAR GENERATION (MWH/YEAR)[A]	2011 ENERGY USE AT SITE (MWH)[B]	DC CAPACITY FACTOR	AC CAPACITY FACTOR[C]	ANNUAL YIELD (KWH/KWP)	PERFORMANCE RATIO
Site 1	4,901	0	19.2%	22.3%	1,678	78.7%
Site 2	7,552	0	19.3%	23.4%	1,689	79.0%
Site 3	6,531	0	19.2%	23.4%	1,681	78.7%
Site 4 PWTP	272	1,659	18.9%	21.4%	1,659	78.0%
Site 5 STWTP	1,375	2,046	19.3%	22.0%	1,692	79.3%

Notes:

[A] First year generation represents the expected generation of the system during its first year of operation. This does not reflect the generation over the expected lifetime of the project.

[B] Sites 1, 2, and 3 do not currently have SCVWD loads. Sites 4 and 5 (The PWTP and STWTP) consume energy; in 2011 the annual energy consumption at these sites is listed in the table above. As can be seen, the solar PV generation would partially offset this load at Sites 4 and 5, but not completely.

[C] The ac capacity factor is calculated using the inverter nameplate rating.

6.1 GREENHOUSE GAS EMISSIONS BENEFITS

In 2011, PWRPA provided a report[6] to SCVWD stating that the electricity delivered to SCVWD had created 54 pounds of CO_2e (Carbon Dioxide equivalent emissions[7]) emissions for every MWh delivered. Assuming the maximum capacity at Sites 1 through 5, the systems could offset just over 1,114,000 pounds of CO2e emissions during the first year when taking into account the 20,631 MWh of technical generation potential.

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[6] Report provided to Black & Veatch titled "Exhibit A 2011 Emission Factor of Electricity provided by the Power & Water Resources Pooling Authority to the Santa Clara Valley Water District", document titled "20110611_PWRPA_SCVWD_TCR.pdf")

[7] Carbon Dioxide equivalent (CO2e) is a metric measurement of the emissions from various greenhouse gases that is based on their global warming potential.

7.0 Financial Analysis

There are several approaches to developing a solar PV project. Major factors in the development approaches are the ability to take advantage of financial incentives. Each development option has certain benefits regarding financing costs, use of tax incentives, project control; and certain risks regarding financial risks, and development/construction risks.

This section first discusses applicable renewable energy financial incentives, and then discusses attributes of four development approaches: build/own, power purchase agreement, pre-pay power purchase agreement, and sale/leaseback.

7.1 RENEWABLE ENERGY FINANCIAL INCENTIVES

A number of financial incentives are available for the installation and operation of renewable energy technologies. These incentives can substantially influence profitability and can make the difference between a non-viable and a viable project. The following discussion provides a list of existing incentives that are available to new renewable energy facilities. Although many of these incentives are designed as tax credits, it may still be possible for non-taxable entities to benefit from the incentives by establishing facility ownership through a taxable third-party entity or other project structures. The applicability of each incentive to a range of ownership structures is provided at the end of the next section. It should be noted that the intent of this section is to provide general information on available incentives. Black & Veatch cannot provide tax advice concerning the implications of the specific incentive programs or ownership structures, and SCVWD is advised to seek expert tax advice before finalizing business structure selection. The following section covers both federal and state incentives. Federal incentives are discussed first.

7.1.1 Federal Incentives

Black & Veatch has assessed the incentives available from the U.S. government and found the following, which are discussed further in this section, to have the most potential to assist SCVWD in lowering project costs:

- Investment Tax Credit (ITC)
- Modified Accelerated Depreciation

The incentives provided by the federal government, particularly the ITC grant and accelerated depreciation, provide a powerful economic driver for solar projects. The remainder of this section highlights the key features of the two incentive programs identified above.

Investment Tax Credit (ITC)

The Investment Tax Credit (ITC) is a corporate tax credit available to projects to assist in financing of a range of renewable energy projects. The ITC, with reference to solar PV installations, consists of a tax credit valued at 30 percent of the project cost basis with no maximum credit limitations.

The ITC may only be claimed by a taxable entity who owns the generating facility. The equipment must generally be new, and meet industry quality and performance standards. The *American Recovery and Reinvestment Act of 2009* extended the ITC such that solar projects are eligible for the credit as long as they are in service by December 31, 2016.

SCVWD as a non-tax paying entity is not directly eligible for the ITC. However, the project may be able to be partly subsidized with the ITC through partnerships between SCVWD and taxable counter-parties. As the ITC is a tax credit, it may only be attractive to entities with a large tax appetite. Certain investors, termed "tax equity" investors, are motivated primarily by the large tax benefits these projects provide.

Modified Accelerated Depreciation

Section 168 of the Internal Revenue Code contains a Modified Accelerated Cost Recovery System (MACRS) through which certain investments in biomass, solar, wind, and geothermal property can be recovered through accelerated depreciation deductions. There is no expiration date on the program. Under this program, certain power plant equipment may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation, while other equipment may also receive (less) favorable depreciation treatment.

The MACRS allows eligible solar PV facilities to receive a five year accelerated depreciation of the asset for tax purposes according to the five year property MACRS schedule.[8] To be eligible for classification as a 5-year property under MACRS, the facility must be a solar PV property and meet the same eligibility requirements of the ITC (as described above). Importantly, this includes that the facility must be owned by a taxable entity.

If the ITC is used in combination with MACRS, then the value of the facility that can be used for accelerated depreciation reduces to 85 percent.

7.1.2 State Incentives

On a state level, California has enacted the California Solar Initiative (CSI). The CSI is a program that provides rebates to customers of an investor owned utility (IOU) in California. These rebates can be taken based on the expected performance (expected performance based buydown – EPBB), or performance (performance based incentive – PBI). The project sizes discussed above would be most appropriate for the PBI incentive. The rebate values for the PBI step down based on how many MW have been installed under the program. A summary of past and current steps is shown in the table below. It should be noted that the CSI is in the last step of the program and incentives may be exhausted in the near term. Municipal utilities have their own solar rebate programs associated with the CSI. Because SCVWD purchases energy from the Power and Water Resources Pooling

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[8] Year 1 = 20%, Year 2 = 32%, Year 3 = 19.2%, Year 4 = 11.52%, Year 5 = 11.52%, Year 6 = 5.76%.

Authority (PWRPA) at the locations being considered for this solar PV feasibility study, they cannot take advantage of the CSI.

Table 7-1 Past and Current CSI PBI Rates ($/kWh)

STEP	STATEWIDE MW IN STEP	COMMERCIAL	GOVERNMENT/NON-PROFIT
5	160	$0.22	$0.32
6	190	$0.15	$0.26
7	215	$0.09	$0.19
8	250	$0.044	$0.139
9	285	$0.032	$0.114
10*	350	$0.025	$0.088

*** Current step for PG&E customers. Approximately 70 MW remaining in this step.**

7.2 DEVELOPMENT APPROACHES

There are several approaches to developing a solar PV facility. Four venues that are prevalent or applicable to SCVWD are discussed here:

- Build and Own
- Power Purchase Agreement
- Pre-pay Power Purchase Agreement
- Sale and Leaseback (not included in financial analysis)

7.2.1 Build and Own

SCVWD has the option to own the project themselves, and enter into an Engineer, Procure, Construct (EPC) contract with a partner to develop the project. SCVWD would not be able to take advantage of any tax incentive programs that are available to assist in funding renewable energy projects.

The key attributes of a structure involving SCVWD ownership are described below.

- **Financing Costs –** The project could be financed entirely by SCVWD using low-cost capital, reducing the aggregate cost of the facility to SCVWD.
- **Use of Tax Incentives** – SCVWD would not be able to take advantage of tax subsidies. SCVWD could consider creating a subsidiary that would be taxable. This option is not explored in this report.

- **Project Control –** Responsibility for project development, construction (through an EPC contractor), and operations and maintenance (through an O&M agreement) lies with SCVWD.
- **Prevalence –** Direct project ownership by taxable companies is a common structure used to develop renewable energy projects. It is not typical for this structure to be used by a non-taxable entity.

The risks involved for SCVWD in developing a solar PV project include:

- **Financial Risk** – SCVWD would take on the financial risk of this option, with a large upfront capital investment.
- **Development/Construction Risk** – SCVWD would be responsible for all development, construction, O&M and performance risks under this structure.

7.2.2 Power Purchase Agreement

The purchase of renewable energy through a power purchase agreement (PPA) with a developer is the most common way in which renewable energy projects have been developed in the recent past. PPAs provide low-risk delivery of power to the purchaser, usually for a set cost per unit of energy, while largely shielding the purchaser from project risks.

The key attributes of a PPA structure are described below.

- **Financing Costs –** The project could be financed entirely by the developer.
- **Use of Tax Incentives** – The developer would be able to take advantage of tax incentives, primarily the ITC.
- **Project Control –** Responsibility for project development, construction, and operations and maintenance lies with the developer.
- **Prevalence –** PPA arrangements are very common as they eliminate the need for upfront capital to the owner, and the burden of O&M lies with the developer.

The risks involved in entering an agreement under a PPA structure include:

- **Financial Risk** – There is minimal financial risk to SCVWD with this approach.
- **Development/Construction Risk –** The development and construction risk profile for SCVWD is very low as the counter-party or developer is responsible for all project development and construction risk.

It should be noted that ownership of the facility remains with the developer unless transfer provisions are included in the PPA agreement. Transfer options were not included in this analysis.

7.2.3 Pre-Pay Power Purchase Agreement

Also applicable to SCVWD is the PPA pre-pay option. The PPA pre-payment option follows the general form of a conventional PPA; however, payment by SCVWD for all or part of the power is made in one lump sum to the developer at the beginning of the PPA term. SCVWD would likely make ongoing payments for electricity beyond the pre-paid amount and possibly a portion of the O&M costs.

The key attributes of a project employing the pre-paid PPA structure are described below:

- **Financing Costs –** SCVWD would be able to use their low-cost of capital to fund the pre-payment of the PPA, while the private owner would have to access more costly commercial debt and equity markets to fund the balance of the project costs. In effect, SCVWD is financing a portion of the project construction costs upfront.
- **Use of Incentives –** Because the PPA pre-payment would be made with a private taxable developer, the project would be eligible for tax incentives.
- **Project Control –** The developer would generally be responsible for the construction and O&M of the project.
- **Prevalence –** Pre-paid PPA structures are relatively uncommon, but increasing in frequency, particularly with wind projects.

SCVWD would have to make a fairly large, upfront financial commitment to enter into such an agreement. Additionally, the contracting structure for such an arrangement can be complicated and typically makes economic sense for large systems. The risks of entering into a pre-pay PPA agreement would need to be carefully weighed against the advantage of securing low-cost power. In all other respects, this option would be very much like a standard PPA. The risks involved in entering an agreement under a pre-paid PPA structure include:

- **Financial Risk** – The large debt burden in the form of pre-paying for future electricity in advance of delivery can be viewed as relatively high risk. SCVWD is essentially accepting the role that would traditionally be filled by project financiers. Prudent due diligence of the project and the proposing counter-party would be necessary.
- **Development/Construction Risk –** The development and construction risk profile for SCVWD is very low as the counter-party or developer is responsible for all project development and construction risk.

It should be noted that ownership of the facility remains with the developer unless transfer provisions are included in the PPA agreement. Transfer options were not included in this analysis.

7.2.4 Sale and Leaseback (not included in financial analysis)

The sale/leaseback project structure can take on a number of forms. One option would involve SCVWD developing the facility and selling it to an investor who has interest in claiming the ITC credit at, or within three months of, the in-service date. The investor would then lease the property back to SCVWD for a period less than the useful life of the plant. SCVWD would have the option to purchase the property at a fair market value at the end of the lease term.

- **Financing Costs –** The project could be financed entirely by SCVWD using low-cost capital, reducing the aggregate cost of the facility to SCVWD.
- **Use of Tax Incentives** – SCVWD would not be able to take advantage of tax subsidies, however the investor to whom the facility is sold would be able to take advantage of tax incentives, primarily the ITC.
- **Project Control –** Responsibility for project development and construction (through an EPC contractor) lies with SCVWD. It is likely that the operations and maintenance (through an O&M agreement) will also lie with SCVWD through the leaseback.
- **Prevalence –** The sale and leaseback approach is fairly common by taxable companies. It is not typical for this structure to be used by a non-taxable entity.

SCVWD would have to make a fairly large, upfront financial commitment to enter into such an agreement. The risks of doing so would need to be carefully weighed against the advantage of securing low-cost power. In all other respects, this option would be very much like a standard PPA, and as discussed in the sections below, is evaluated with the PPA option.

The risks involved in entering sale and leaseback structure include:

- **Financial Risk** – SCVWD would take on the financial risk of this option, with a large upfront capital investment. SCVWD would also take on the risk of energy production.
- **Development/Construction Risk** – SCVWD would be responsible for all development and construction. When the facility is leased back, SCVWD would be responsible for O&M and performance risks under this structure.

It should be noted that ownership of the facility remains with the third party unless transfer provisions are included in the agreement for an ownership transfer at a certain period. The financials of this approach are very similar to the PPA approach. Therefore the sale/leaseback approach is not assessed in the financial analysis included in the following sections.

7.3 FINANCIAL ANALYSIS

Black & Veatch performed a financial analysis for Sites 1 through 5. Sites 1, 2 and 3 have similar parameters and are discussed in one section, while Sites 4 and 5 have similar parameters and are discussed together in a separate section.

The following three development approaches were modeled: 1) the build/own option as described above, 2) the PPA as described above, 3) Black & Veatch also included the pre-pay PPA analysis to show a range of development approaches and financial impacts. The modeling performed for this feasibility study does not reflect the nuances between the PPA and sale/leaseback option; therefore the results of the sale/leaseback approach are the same as the PPA approach. Each development approach has unique parameters that may impact a financial analysis. These parameters are summarized in the sections below.

7.3.1 Approach

To assess the financial attractiveness of theses development approaches for the various sites, Black & Veatch assessed the financial attractiveness of the three development options in three different scenarios:

1) For Sites 1, 2 and 3 the PG&E feed-in tariff (FIT) rate is assumed to be available to the project, and equal to the value of the solar energy. In this scenario, a PPA or pre-pay PPA with a developer is not necessarily applicable. Black & Veatch includes this case, however because an agreement could be made with a developer (such as a lease agreement) where the economics are the same as a PPA or pre-pay PPA.
2) For Sites 4, and 5, the first scenario assessed assumes the value of solar energy is the aggregate value of the PWRPA energy charges offset by the PV system in a year.
3) The final scenario assessed for Sites 4 and 5 assumes the value of solar energy is the aggregate value of PG&E E-19 energy charges offset by the solar PV system.

The financial metric used for this evaluation includes the net present value (NPV) of solar PV savings. The NPV is calculated by estimating the present value of cash flows over the lifetime of the project, with appropriate escalation and degradation assumptions applied. The NPV presented is the NPV of solar savings, meaning it is the NPV of the money saved by using solar PV generation less the NPV of the cash flows of SCVWD related to the project. A positive NPV indicates a possibly good investment, a zero NPV indicates an investment that would not necessarily have a positive or negative financial implication, and a negative NPV indicates a project that would not necessarily be a good financial investment.

7.3.2 Assumptions

Black & Veatch performed the scenario analysis described above with assumptions regarding the capital cost of each system, the value of the solar energy based on different values of energy purchases that are offset by the solar, and other financial parameters. These assumptions are summarized in this section.

Black & Veatch reviewed publicly and privately available resources for cost information such as the CSI database, NREL's Open PV Project, and Energy Acuity. Black & Veatch also relied on market knowledge of current solar PV prices. Black & Veatch assumed the interconnection for the Site 4 - PWTP and Site 5 - STWTP would not require significant upgrades to the electrical infrastructure and the cost of these upgrades are included in the capital cost estimate. The costs listed below are inclusive of administration, permitting, design, and construction management. The following costs are expected for systems of this size. Site 4 - PWTP and Site 5 - STWTP costs are higher given the smaller system sizes and lack of economies of scale. The cost estimates are summarized in the table below.

Table 7-2 Cost Estimates

SYSTEM	SYSTEM SIZE (MWP)	MOUNTING	ESTIMATED CAPITAL COST	ESTIMATED INTERCONNECTION COST	TOTAL ESTIMATED CAPITAL COST
Site 1	2.93	Ground	$3.60/Wp	$40,400	$10,588,400
Site 2	4.5	Ground	$3.60/Wp	$41,600	$16,241,600
Site 3	3.9	Ground	$3.60/Wp	$39,200	$14,079,200
Site 4 – PWTP	0.165	Ground	$4.00/Wp	$0	$660,800
Site 5 – STWTP	0.820	Ground	$3.80/Wp	$0	$3,116,000

Other financial assumptions were defined based on knowledge of SCVWD non-taxpaying status, and typical parameters in for the three different development approaches. Black & Veatch did not include the cost of land as SCVWD currently owns these lands. These financial analysis assumptions are summarized in the table below.

Table 7-3 Financial Analysis Assumptions[9]

PARAMETER	BUILD/ OWN	PPA	PRE-PAY PPA	NOTES
Economic Life (years)	25 years	25 years	25 years	Typical economic life for a PV system is between 20 and 30 years. B&V has assumed a 25 year economic life for these projects. It is assumed that the off-take agreement will last for the full economic life.
MACRS Depreciation	No	Yes	Yes	Based on development structure.
ITC	No	Yes	Yes	Based on development structure.
CSI	Yes and No	Yes and No	Yes and No	Included for scenario3 only.
Tax Rate	0%	41%	41%	Based on typical parameters and development structure.
Debt Percentage	0%	60%	55%	Based on typical parameters and development structure.
Debt Rate	NA	7%	7%	Based on typical parameters.
Debt Term	NA	25 years	25 years	Based on economic life and typical parameters.
Equity Return	2%	7%	7%	Based on typical parameters.
PPA Price Escalation	2.5%	2.5%	2.5%	Based on typical parameters such as inflation.
PPA Term	25 years	25 years	25 years	Based on economic life and typical parameters.
Solar Degradation	0.7%	0.7%	0.7%	Based on typical warranties.
PWRPA & PG&E Rate Escalation	3.0%	3.0%	3.0%	Based on typical parameters such as inflation and energy prices.
Scenario 1: Site 1,2, and 3 Value of Solar Energy	$0.098/kWh	$0. 098/kWh	$0. 098/kWh	Based on the PG&E Feed In Tariff (FIT) rate[10]. This assumes a contract start in 2010 and a 20 year contract. It is expected that a contract start in a later year would have a similar rate.
Scenario 2: Sites 4 and 5 Value of Solar Energy *	$0.08/kWh	$0.08/kWh	$0.08/kWh	Based on a typical year and PWRPA energy prices. Further described in note below. This is not a levelized value.
Scenario 3: Sites 4 and 5 Value of Solar Energy *	$0.11/kWh	$0.11/kWh	$0.11/kWh	Based on a typical year and PG&E E-19 energy prices. Further described in note below. This is not a levelized value.

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[9] Note that solar PV generally offsets kWh charges and has limited impact on kW charges. KW charges are typically based on the peak kW demand within an hour. Because of the variability of clouds and solar resource, demand charges are typically not impacted by solar PV generation. This assumption was implemented in this analysis.

[10] http://www.pge.com/includes/docs/pdfs/b2b/wholesaleelectricsuppliersolicitation/Feedin_Tariffs_FAQs.pdf

Notes:
*** It should be noted that the value of solar energy depends on several regulatory factors and mandates such as Renewable Portfolio Standards (RPS) and Renewable Energy Credit (REC) prices. For planning purposes, the Value of Solar Energy is calculated by estimating solar PV generation over a year, applying PWRPA and PG&E time of day rates (TOD) to each hour of the year to calculate energy cost at each hour, and calculating the average cost per kWh over the year. This process accounts for the higher value of energy during certain times of the day and year, and the benefit that solar PV brings as it generates primarily during those high value times. This value is used to estimate the value of the energy offset by solar PV generation.**

7.3.3 Site 1, 2 and 3 (Scenario 1)

This section includes the NPV results for Sites 1, 2, and 3 for scenario (1) assuming the systems feed into the PG&E system and receive the PG&E FIT rate. As expected, the development approach (1) build and own is the least attractive in terms of NPV. This is largely driven by the inability to take advantage of the ITC and MACRS incentives. A pre-pay PPA approach for sites 1, 2 and 3 may be economical.

Table 7-4 Site 1, 2 and 3 NPV Results (Scenario 1)

SITE	DEVELOPMENT APPROACH	NPV OF SAVINGS WITH PV ($000) * (SCENARIO 1)
Site 1	Build-and-Own	-$3,499
	PPA	-$1,497
	Pre-Pay PPA	$190
Site 2	Build-and-Own	-$5,199
	PPA	-$2,130
	Pre-Pay PPA	$465
Site 3	Build-and-Own	-$4,529
	PPA	-$1,869
	Pre-Pay PPA	$381

*** NPV is based on the economic life listed in Table 7-3.**

7.3.4 Site 4 and 5 (Scenarios 2 and 3)

This section includes the NPV results for Sites 4 and 5 for two scenarios (2) assuming the systems offset energy purchases from PWRPA, and (3) assuming the systems offset energy purchases from PG&E and can take advantage of the CSI. As expected, the development approach (1) build-and-own case is the least attractive in terms of NPV. This is largely driven by the inability to take advantage of the ITC and MACRS incentives. The cases which take advantage of the CSI are more attractive in terms of NPV given the CSI rebate and the higher value of solar energy.

Table 7-5 Site 4 and 5 NPV Results (Scenarios 2 and 3)

SITE	DEVELOPMENT APPROACH	NPV OF SAVINGS WITH PV ($000) * (SCENARIO 2)	NPV OF SAVINGS WITH PV ($000) * (SCENARIO 3)
Site 4	Build-and-Own	-$93	$113
	PPA	-$79	$206
	Pre-Pay PPA	$26	$295
Site 5	Build-and-Own	-$798	$809
	PPA	-$209	$1,234
	Pre-Pay PPA	$288	$1,649

*** NPV is based on the economic life listed in Table 7-3.**

8.0 Conclusions

SCVWD has investigated solar PV feasibility in 2001 and installed solar PV facilities successfully in 2004. The market has changed significantly since the 2001 analysis performed by SCVWD. The value of offset emissions has decreased, but the cost of solar PV systems has also decreased. The O&M cost assumptions were fairly low.

Currently, SCVWD has several sites that are suitable for the development of a solar PV facility. The sites, expected energy production, potential system sizes and estimated capital costs are listed in the table below.

Table 8-1 Overall Site Summary

SITE	FIRST YEAR GENERATION (MWH/YEAR)	SYSTEM SIZE (MWP)	SYSTEM SIZE (MWAC)	TOTAL ESTIMATED CAPITAL COST
Site 1	4,901	2.93	2.5	$10,588,400
Site 2	7,552	4.5	3.7	$16,241,600
Site 3	6,531	3.9	3.2	$14,079,200
Site 4 – PWTP	272	0.165	0.146	$660,800
Site 5 - STWTP	1,375	0.820	0.720	$3,116,000

The economics of developing these facilities varies based on several parameters such as the development approach and assumptions regarding the value of solar energy. Black & Veatch attempted to perform an analysis which would show the benefits of different development approaches. The results of this analysis are shown in the table below. As expected, the build and own case is the most expensive. This is largely driven by the inability to take advantage of the ITC and MACRS incentives.

The general trend shows that systems that use the pre-pay PPA approach are more economical than the PPA and build-and-own. Black & Veatch would recommend a pre-pay PPA approach but notes that this type of structure is complicated and may incur several fees. Alternately, the PPA option is widespread and appropriate for SCVWD however based on the results presented below does not appear to be a financially attractive approach at this time. Sites 4 and 5 appear to be financially viable under a pre-pay PPA approach in scenario 2. Sites 4 and 5 appear to be financially attractive under build-and-own, PPA and pre-pay PPA in scenario 3. The larger sites (Sites 1, 2 and 3) may also make economic sense with the pre-pay PPA approach (scenario 1).

Table 8-2 NPV Results

SITE	DEVELOPMENT APPROACH	NPV OF SAVINGS WITH PV ($000) * (SCENARIO 1)
Site 1	Build-and-Own	-$3,499
	PPA	-$1,497
	Pre-Pay PPA	$190
Site 2	Build-and-Own	-$5,199
	PPA	-$2,130
	Pre-Pay PPA	$465
Site 3	Build-and-Own	-$4,529
	PPA	-$1,869
	Pre-Pay PPA	$381

SITE	DEVELOPMENT APPROACH	NPV OF SAVINGS WITH PV ($000) * (SCENARIO 2)	NPV OF SAVINGS WITH PV ($000) * (SCENARIO 3)
Site 4	Build-and-Own	-$93	$113
	PPA	-$79	$206
	Pre-Pay PPA	$26	$295
Site 5	Build-and-Own	-$798	$809
	PPA	-$209	$1,234
	Pre-Pay PPA	$288	$1,649

FINAL

ENERGY OPTIMIZATION PROJECT

Liquid Fuels Analysis

B&V Project No. 178292

Prepared for

Santa Clara Valley Water District

11 FEBRUARY 2013

Table of Contents

1.0 Executive Summary 1
2.0 Existing Mobile Equipment 3
2.1 Existing Mobile Equipment Summary 3
2.2 Existing Mobile Equipment Energy Balance 3
2.3 Existing Mobile Equipment Energy Efficiency 3
3.0 Replacement Equipment Options 7
3.1 Cost effectiveness comparison 8
4.0 Refueling Infrastructure Requirements 14
4.1 Electric Vehicle Recharging Infrastructure 14
4.2 Natural GAs Refueling Infrstructure 14
5.0 Maintenance Requirements 16
6.0 Conclusions and Recommendations 17

TABLES

Table 1 Existing Vehicle Types and Fuel Economy 5
Table 2 Vehicle Cost Comparison 8
Table 3 In-Kind Replacement Vehicle Options 9
Table 4 Hybrid Replacement Vehicle Options 10
Table 5 Dedicated Electric/Plug-in Hybrid Replacement Vehicle Options 12
Table 6 Compressed Natural Gas (CNG) Replacement Vehicle Options 13

FIGURES

Figure 1 Vehicle Count and Mileage by Year and Type 6
Figure 2 SCVWD Maintenance Yard showing potential plug-in and CNG facilities 15
Figure 3 Typical Layout for a Fast Fill CNG Station 15
Figure 4 Current Fleet Vehicles and Fuel Economy and Hybrid Option Fuel Economy 18

1.0 Executive Summary

As part of SCVWD's Energy Optimization Plan the use of gasoline and diesel fuel by The District mobile equipment was assessed by Black & Veatch. The assessment evaluated alternatives for light duty vehicles included SUVs and sedans but does not include any vehicles i.e. trucks and equipment above Class 2 rating. The assessment primarily consisted of evaluation of the current fuel use, commercially available options for Hybrids, CNGs, and dedicated electric vehicles, associated facilities for each fuel alternative, and required maintenance services for each vehicle type.

The main conclusions from the Liquids Fuel Analysis are:

- The District consumed approximately 66,300 gallons of gasoline and 2,100 gallons of diesel in last year, or 68,700 gallons of gasoline equivalent. Based on the provided cost of gasoline and diesel, The District spent approximately $212,000 on gasoline and $7,000 on diesel for a total cost of $219,000.
- Based on The District's current replacement policy (12 years, 125,000 miles), and FY2013 replacements, a significant number of vehicles will be up for replacement the next couple of years.
- The existing fleet average fuel economy for the past year was 16.9 miles/GGE.
- There are multiple hybrid vehicle options commercially available to include sedans, light trucks, and SUVs. There are commercially available options for dedicated electric/plug-in hybrids and CNG vehicles, but they are limited to the sedan class.
- No refueling facilities are needed for hybrid vehicles. While a CNG dispensing unit(s) can be added to the existing refueling island, there is limited space for CNG refueling station on existing property. The estimated cost for a CNG Station with dispensing units to meet The District's initial needs and prepare for future expansion is estimated to be $300,000-$500,000. Dedicated electric vehicles would be recharged by plug-in receptacles which infrastructure could be installed in existing islands between parking spaces. Cost of this infrastructure is estimated at $75, 000-$150,000 depending on how many charging stations are desired. The District has four (4) 240 volt chargers in the carport system.
- SCVWD staff are trained on maintenance on hybrid vehicles with one exception and will need training for this staff member as well as additional hybrid maintenance staff if additional hybrids are added to the fleet. No building modifications are needed for hybrid vehicle maintenance and dedicated electric vehicle maintenance (as long as 240 V service is available). Dedicated electric vehicles would be recharged by plug-in receptacles which infrastructure could be installed in existing islands between parking spaces. Modifications most likely would need to be made to existing buildings for CNG maintenance which could be costly. Training for existing staff would be needed for them to work on dedicated electric or CNG vehicles.

Based on the results of this assessment, Black & Veatch recommends that SCVWD continue purchasing hybrid vehicles where possible as part of their replacement program for the following reasons:

- There are commercial available hybrid vehicles for cars, SUVs, and light trucks. The number of available hybrid vehicles has grown in the past years and is expected to increase in the future. Further, the fuel economy of hybrids is getting better. Hybrids are cost effective when compared to traditionally fueled and dedicated electric vehicles. Finally, there are limited commercial options (sedans or 3rd party conversions) for CNG and dedicated electric vehicles.

- Of the vehicles with available hybrid options, continued conversion to available hybrid vehicles will increase fuel efficiency for cars, SUVs, and light trucks (Rangers, F-150s) from an estimated 19.9 miles/GGE (Existing Fleet) to 30.6 miles/GGE, a 54 percent increase in fuel economy (NOTE: average fuel economy based on miles driven in the past year by vehicle type). Figure 4 shows the potential fuel economy gain for a hybrid conversion based on commercially available vehicles. Fuel economy gains are also shown in Table 4.
- No refueling facilities are needed for hybrid vehicles. While a CNG dispensing unit(s) can be added to the existing refueling island, there is limited space for CNG refueling station on the existing property. Dedicated electric vehicles would require infrastructure upgrades for plug-in receptacles between parking spaces.
- SCVWD staff are trained on maintenance on hybrid vehicles. Additional trained maintenance staff will be required for a hybrid fleet conversion. However, since almost all of the existing staff is already trained, continuing the existing program to purchase hybrid vehicles when possible is more beneficial and economic than either the Dedicated electric or CNG options. Further, no building modifications are needed for hybrid maintenance.
- Training for existing staff would be needed for maintenance on dedicated electric or CNG vehicles.
- No building modifications are needed for dedicated electric vehicle maintenance (as long as 240 V service is available). Modifications most likely would need to be made to existing buildings for CNG maintenance which could be costly.

2.0 Existing Mobile Equipment

2.1 EXISTING MOBILE EQUIPMENT SUMMARY

The Liquid Fuels Analysis includes an assessment of The Districts light duty vehicles which including sedans, SUVs, and trucks below a Class 2 rating. The District provided Black & Veatch a database of their existing mobile equipment, 190 vehicles. From this database Black & Veatch classified the 190 vehicle into one of ten different vehicle types. Table 1 provides the 10 different vehicle types, vehicle count by type, and average mileage per vehicle by vehicle type.

The District also provided Black & Veatch a list of the vehicles expected for replacement in FY2013. Currently, SCVWD expects to replace 35 light duty vehicles in 2013, detailed by vehicle type in Table 1. According to SCVWD staff, the replacement schedule is based on a 12 year or 125,000 mile replacement program. Table 1 also shows additional information discussed later in this memorandum.

Figure 1 is a different representation of the SCVWD fleet showing the vehicle count by model year and vehicle type and the average miles per vehicle by model year. Based on the existing mobile equipment data provided to Black & Veatch and represented in Table 1 and
Figure **1** the following are noted:

- 99 of the 190 vehicles, or approximately 52 percent, are model year 2001, 2002, and 2003
- 33 of the 35 vehicles up for replacement in FY2013 are 2001 model year. Of the 34 2001 model year vehicles, 33 are scheduled for replacement in FY2013.
- Based on The District's current replacement policy (12 years, 125,000 miles), and FY2013 replacements, a significant number of vehicles will be up for replacement the next couple of years.

2.2 EXISTING MOBILE EQUIPMENT ENERGY BALANCE

Using publically available information on average fuel economy and miles driven by each vehicle from the provided database, Black & Veatch calculated the latest year's gasoline and diesel consumption by The District for the mobile equipment. Based on this methodology, The District consumed approximately 66,300 gallons of gasoline and 2,100 gallons of diesel in last year. Black & Veatch assumed a 1.14 gallon of gasoline per gallon of diesel equivalent basis to calculate the total fuel consumed on a gasoline gallon equivalent (GGE) basis. Table 1 includes the gallons of gasoline equivalent consumed by The District for the latest year by vehicle type. The total gasoline gallon equivalent consumed for the latest year is 68,700 gallons of gasoline equivalent.

According to SVWD staff, the current average cost of gasoline is $3.20/gallon (without tax) and diesel is $3.20/gallon (without tax). Based on the cost of gasoline and diesel, The District spent approximately $212,000 on gasoline and $7,000 on diesel for a total cost of $219,000.

2.3 EXISTING MOBILE EQUIPMENT ENERGY EFFICIENCY

Black & Veatch estimated the fuel economy by vehicle model and age based on publically available information. Black & Veatch assumed combined city and highway fuel economy for each vehicle in the assessment. Several sources were used to estimate the average fuel economy for each vehicle in the fleet. Two of the main sources were www.fueleconomy.gov, an EPA sponsored website, and www.fuelly.com, publicly provided estimates based on actual observed fuel economy by vehicle owners.

Table 1 shows the estimated miles driven, gallons of gasoline equivalent consumed, and fuel economy (miles/GGE) by vehicle type. The fleet average fuel economy was 16.9 miles/GGE.

Table 1 Existing Vehicle Types and Fuel Economy

VEHICLE TYPE	2012 VEHICLE COUNT	2013 EXPECTED REPLACEMENT	2012 AVG. MILES / VEHICLE	LAST YEAR MILES DRIVEN	LATEST YEAR GALLON GASOLINE EQUIVALENT (GGE) CONSUMED	FUEL ECONOMY MILES/GGE
Sedan (Taurus, Contour)	33	13	73,302	146,521	6,996	20.9
Car Hybrid (Prius)	6	0	85,008	40,940	890	46.0
Small Truck (Ranger)	35	6	67,501	244,088	16,038	15.2
F-150	23	2	46,510	194,224	12,071	16.1
F-250	19	9	60,776	82,200	6,274	13.1
F-350	2	0	91,755	17,766	1,409	12.6
SUV (Explorer, Cherokee)	29	1	100,022	182,750	11,875	15.4
SUV Hybrid (Escape)	19	0	20,058	125,263	4,444	28.2
Minivan (Caravan)	6	1	51,945	24,465	1,318	18.6
Van (E-350)	18	3	58,234	104,290	7,396	14.1
Total	190	35	64,953	1,162,507	68,713	16.9

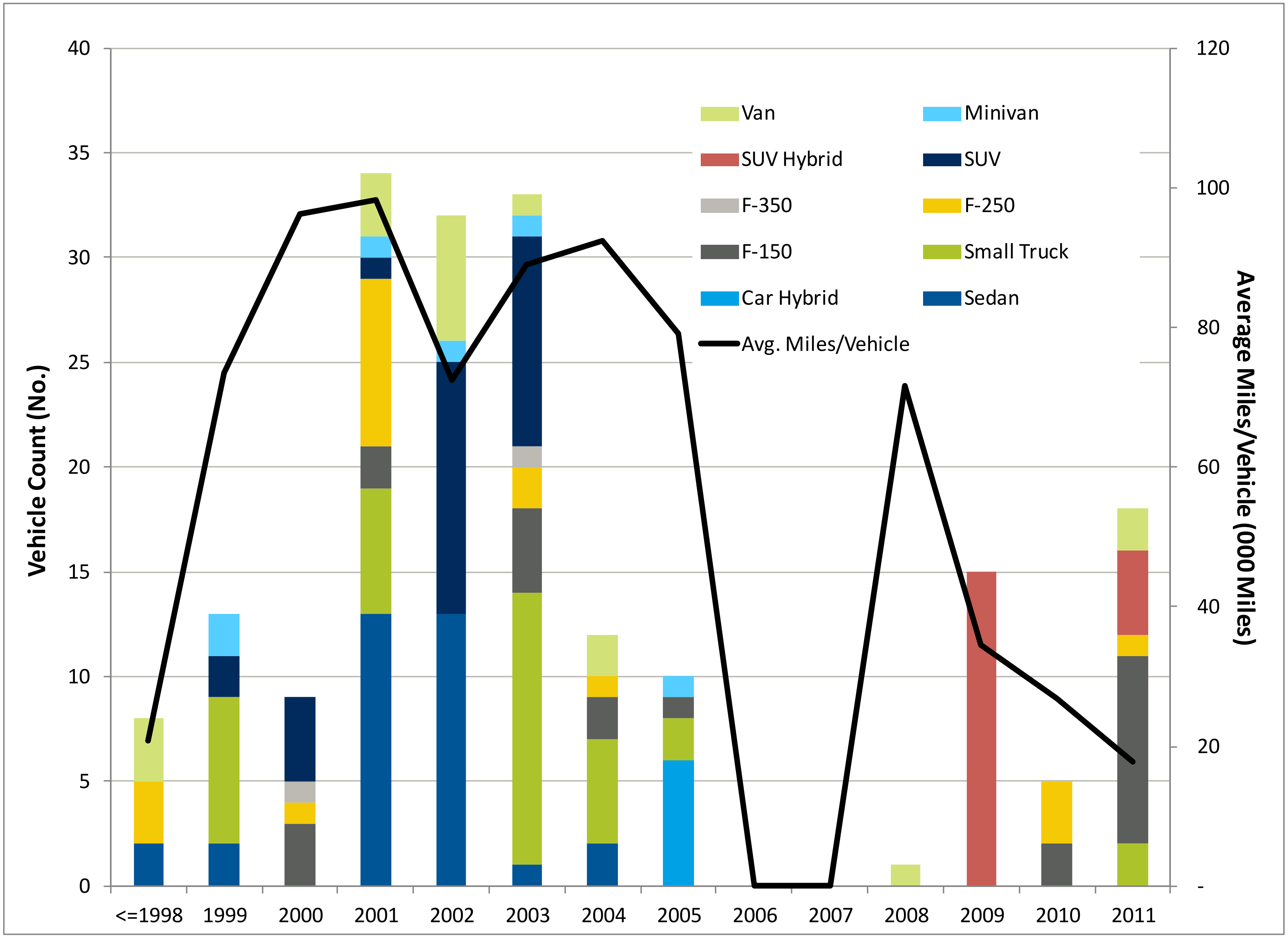


Figure 1 Vehicle Count and Mileage by Year and Type

3.0 Replacement Equipment Options

This section of the report assesses possible replacement equipment options for four alternatives:

1. Replace In-Kind (new equipment of the same class or category)
2. Hybrid Electric Vehicles
3. Dedicated Electric/Plug-In Hybrid Vehicles
4. Compressed Natural Gas (CNG) Vehicles

For each alternative, Black & Veatch only considered commercially available vehicles, this assessment does not include vehicles modified by a 3rd party. Further, Black & Veatch assumed The District would keep the same mix of vehicles types when assessing replacement options.

Table 3 shows in-kind or similar replacement options for each vehicle type. The table includes information for both the existing fleet and in-kind replacement vehicles. The existing fleet vehicle information includes vehicle count, number of expected replacements in 2013, estimated fuel economy on a $/gallon and $/mile basis. For in-kind replacement vehicles, Table 3 shows the closest vehicle replacement option, estimated fuel economy on a $/gallon and $/mile basis, and the estimated cost of purchasing the vehicle. It should be noted that Ford has discontinued the Ranger (Small Truck Category), therefore Black & Veatch assumed replacement with a Toyota Tacoma. Assessment of the in-kind replacements shows that the sedans, small trucks, minivans, and SUVs have a slight increase in fuel economy, however many of the larger vehicles (F-series and Vans) have either stayed the same or decreased in fuel economy.

Over the last couple years, hybrid vehicles options have increased significantly.

Table 4 shows several hybrid vehicle options that match The District's existing vehicle types. Review of the table shows several hybrid sedan options with a wide range of costs and fuel economy. For the small trucks and F-150 sizes, General Motors has developed hybrid options of the Sierra and Silverado additions that have a 5 to 6 mile/gallon advantage over SCVWD existing vehicles. The table also shows several hybrid options for SUVs ranging from larger SUVs (Tahoe, Yukon) to small options (Escape, Highlander).

Table 4 also includes the fuel economy ($/gallon and $/mile) and the estimated purchase cost for each vehicle. The table also includes a comparison of the key metrics to The District's existing fleet. There are no hybrid options for The District's larger vehicles (F-250s, F-350s, E-350s, or minivans). However, given the wave of new hybrid vehicle options in the past few years, it is reasonable to expect more hybrid options will become available in future years.

Table 5 and Table 6 show dedicated electric/plug-in hybrid and compressed natural gas vehicles currently available on the commercial market. As the tables show, there are only sedan options commercially available. However, traditional gasoline/diesel vehicles can be purchased and converted to CNG by a third party such as BAF Technologies, Baytech Corporation, and NatGasCar. Both tables includes fuel economy and purchase cost for each of the available vehicle options. A comparison to the existing vehicles types is also shown in the tables.

For purposes of calculating fuel economy on a $ per mile basis, Black & Veatch assumed $3.20/gallon of gasoline (without tax), $3.20/gallon of diesel (without tax), $0.09/kWh, and

$0.50/therm. The gasoline, diesel, and electricity rates were provided by SCVWD staff. Natural gas is based on The District's latest current natural gas bills.

Key findings from the assessment of the vehicles options include the following:

- Multiple hybrid options to include cars, light trucks (Chevrolet Silverado), and SUVs (Ford Escape, Chevrolet Tahoe).
- Few commercially available CNG vehicles (Honda Civic CNG). Traditional gasoline/diesel vehicles can be purchased and converted to CNG by a third party such as BAF Technologies, Baytech Corporation, and NatGasCar.
- Few commercially available dedicated electric vehicles (Nissan Leaf). No commercially available options for SUVs, trucks, or vans.

3.1 COST EFFECTIVENESS COMPARISON

The following table provides a representative comparison of the total cost of ownership for the four vehicle types. The analysis includes the following assumptions:

- 12 year useful life
- No financing
- No taxes or tax credits
- No vehicle salvage value at end of useful life
- Effective Discount Rate 2%
- 4 % inflation for fuel and maintenance
- 125,000 total miles

VEHICLE TYPE	PURCHASE PRICE	2012 FUEL COST/MILE	TOTAL FUEL COST (12 YR)	2012 ANNUAL MAINTENANCE COST	NPV OF COST
Conventional Fuel (Ford Taurus)	$26,600	$0.14	$19,779.85	$1,200	$60,281
Dedicated Electric (Leaf)	$37,250	$0.03	$4,238.54	$1,000	$53,073
Hybrid (Toyota Prius)	$24,800	$0.06	$8,477.08	$1,000	$44,862
CNG (Honda Civic)	$26,300	$0.02	$2,825.69	$900	$39,552

Table 2 Vehicle Cost Comparison

The cost comparison does not include needed facility improvements such as charging stations, refueling facilities, CNG handling equipment and training. The Prius Hybrid is considered to be a cost effective alternative since no additional equipment or fueling facilities would be needed as compared to the CNG alternative.

Table 3 In-Kind Replacement Vehicle Options

EXISTING VEHICLE FLEET					IN-KIND VEHICLES			
VEHICLE TYPE	2012 VEHICLE COUNT	2013 EXPECTED REPLACE.	FUEL ECONOMY MILES/GAL.	FUEL ECONOMY $/MILE	VEHICLE TYPE	FUEL ECONOMY MILES/GAL.	FUEL ECONOMY $/MILE	ESTIMATED PURCHASE COST
Sedan								
Contour	4	0	24	$0.13	2013 Fusion	26	$0.12	$21,700
Taurus	29	13	21	$0.16	2013 Taurus	23	$0.14	$26,600
Car Hybrid (Prius)	6	0	46	$0.07	2012 Prius	50	$0.06	$24,800
Small Truck (Ranger)	35	6	15	$0.21	2013 Tacoma	18	$0.18	$25,400
F-150	23	2	16	$0.20	2013 F-150	13	$0.25	$34,500
F-250								
Diesel	4	2	15	$0.21	2013 F-250 Diesel	15	$0.21	$46,900
Gas	15	7	13	$0.25	2013 F-250 Gas	10	$0.31	$39,100
F-350	2	0	14	$0.22	2013 F-350 Diesel	15	$0.22	$49,000
SUV								
Explorer	22	0	15	$0.21	2013 Explorer	20	$0.16	$29,100
Cherokee	7	1	16	$0.19	2013 Cherokee	19	$0.17	$27,500
SUV Hybrid (Escape)	19	0	28	$0.11	2012 Escape	32	$0.10	$30,800
Minivan (Caravan)	6	1	19	$0.17	2013 Caravan	20	$0.16	$28,500
Van (E-350)	18	3	14	$0.23	2013 E-350	12	$0.27	$33,300

Table 4 Hybrid Replacement Vehicle Options

EXISTING VEHICLE FLEET					HYBRID VEHICLE OPTION			
VEHICLE TYPE	2012 VEHICLE COUNT	2013 EXPECTED REPLACE.	FUEL ECONOMY MILES/GAL	FUEL ECONOMY $/MILE	VEHICLE TYPE	FUEL ECONOMY MILES/GAL	FUEL ECONOMY $/MILE	ESTIMATED COST
Sedan								
Contour	4	0	24	$0.13	2012 Prius	50	$0.06	$29,805
Taurus	29	13	21	$0.16	2013 Ford C-MAX Hybrid	47	$0.07	$28,200
Car Hybrid (Prius)	6	0	46	$0.07	2013 Ford Fusion Hybrid	47	$0.07	$27,200
					2012 Honda Civic Hybrid	44	$0.07	$24,050
					2012 Honda Insight	42	$0.08	$23,690
					2012 Toyota Camry Hybrid	41	$0.08	$25,990
					2012 Hyundai Sonata Hybrid	36	$0.09	$25,850
					2012 Kia Optima Hybrid	36	$0.09	$25,700
					2013 Chevrolet Malibu eAssist	29	$0.11	$26,945
					2013 Buick LaCrosse eAssist	29	$0.11	$33,870
					2012 Buick Regal eAssist	29	$0.11	$32,045
Small Truck & F-150 Size								
Small Truck (Ranger)	35	6	15	$0.21	2013 GMC Sierra 2WD Hybrid	21	$0.15	$46,790
F-150	23	2	16	$0.20	2013 GMC Sierra 4WD Hybrid	21	$0.15	$49,990
					2013 Silverado 2WD Hybrid	21	$0.15	$46,420
					2013 Silverado 4WD Hybrid	21	$0.15	$49,620

EXISTING VEHICLE FLEET					HYBRID VEHICLE OPTION			
VEHICLE TYPE	2012 VEHICLE COUNT	2013 EXPECTED REPLACE.	FUEL ECONOMY MILES/GAL	FUEL ECONOMY $/MILE	VEHICLE TYPE	FUEL ECONOMY MILES/GAL	FUEL ECONOMY $/MILE	ESTIMATED COST
F-250								
Diesel	4	2	15	$0.21	No Hybrid Options			
Gas	15	7	13	$0.25	No Hybrid Options			
F-350	2	0	14	$0.22	No Hybrid Options			
SUV								
Explorer	22	0	15	$0.21	2012 Escape Hybrid	32	$0.10	$33,080
Cherokee	7	1	16	$0.19	2013 Highlander Hybrid	28	$0.11	$44,370
SUV Hybrid (Escape)	19	0	28	$0.11	2013 GMC Yukon Hybrid	21	$0.15	$52,470
					2013 Tahoe Hybrid	21	$0.15	$51,970
Minivan (Caravan)	6	1	19	$0.17	No Hybrid Options			
Van (E-350)	18	3	14	$0.23	No Hybrid Options			

Table 5 Dedicated Electric/Plug-in Hybrid Replacement Vehicle Options

EXISTING VEHICLE FLEET					DEDICATED ELECTRIC/PLUG-IN HYBRID VEHICLE OPTION				
VEHICLE TYPE	2012 VEHICLE COUNT	2013 EXPECTED REPLAC.	FUEL ECONOMY MILES/GAL	FUEL ECONOMY $/MILES	VEHICLE TYPE	FUEL ECONOMY KWH/MILE	FUEL ECONOMY MILES/GGE	FUEL ECONOMY $/MILE	ESTIMATED COST
Sedan									
Contour	4	0	24	$0.13	2013 Ford Focus BEV FWD	0.32	105	$0.03	NA
Taurus	29	13	21	$0.16	2013 Volt Plug-in Hybrid*	0.35	98	$0.03	$39,145
Car Hybrid (Prius)	6	0	46	$0.07	2012 Nissan Leaf	0.34	99	$0.03	$37,250
					2012 Toyota Prius Plug-in Hybrid**	0.29	95	$0.03	$39,525
Small Truck (Ranger)	35	6	15	$0.21	No Electric/Plug-In Options				
F-150	23	2	16	$0.20	No Electric/Plug-In Options				
F-250	19	9	14	$0.23	No Electric/Plug-In Options				
F-350	2	0	14	$0.22	No Electric/Plug-In Options				
SUV (Cherokee, Explorer)	29	1	16	$0.20	No Electric/Plug-In Options				
SUV Hybrid (Escape)	19	0	28	$0.11	No Electric/Plug-In Options				
Minivan (Caravan)	6	1	19	$0.17	No Electric/Plug-In Options				
Van (E-350)	18	3	14	$0.23	No Electric/Plug-In Options				

*Assumes 35 kWh/100 miles and 2.7 gallons of gasoline/100 miles
**Assumes combined 29 kWh/100 miles and 0.2 gallons of gasoline/100 miles

Table 6 Compressed Natural Gas (CNG) Replacement Vehicle Options

EXISTING VEHICLE FLEET					CNG VEHICLE OPTION				
VEHICLE TYPE	2012 VEHICLE COUNT	2013 EXPECTED REPLAC.	FUEL ECONOMY MILES/GAL	FUEL ECONOMY $/MILES	VEHICLE TYPE	FUEL ECONOMY MILES/THERM	FUEL ECONOMY MILES/GGE	FUEL ECONOMY $/MILE	ESTIMATED COST
Sedan									
Contour	4	0	24	$0.13	Honda Civic CNG	25	31	$0.02	$26,300
Taurus	29	13	21	$0.16					
Car Hybrid (Prius)	6	0	46	$0.07					
Small Truck (Ranger)	35	6	15	$0.21	No Commercial CNG Options				
F-150	23	2	16	$0.20	No Commercial CNG Options				
F-250	19	9	14	$0.23	No Commercial CNG Options				
F-350	2	0	14	$0.22	No Commercial CNG Options				
SUV (Cherokee, Explorer)	29	1	16	$0.20	No Commercial CNG Options				
SUV Hybrid (Escape)	19	0	28	$0.11	No Commercial CNG Options				
Minivan (Caravan)	6	1	19	$0.17	No Commercial CNG Options				
Van (E-350)	18	3	14	$0.23	No Commercial CNG Options				

4.0 Refueling Infrastructure Requirements

4.1 ELECTRIC VEHICLE RECHARGING INFRASTRUCTURE

Electric Vehicle recharging facilities are virtually nonexistent compared to refueling infrastructure needed for gasoline, diesel and compressed natural gas vehicles. Although the District does have four (4) 240 volt chargers in the carport system.

Hybrids recharge during operation and do not require plug-in recharging unless desired by the operator. If charging is desired, a 120V receptacle for hybrids (240V receptacle is optional for faster charging times) is all that is required. A 240V receptacle is required for dedicated electric vehicles whose sole energy source is electricity. A fueling island with card key and/or electronic payment options can be used for public or private fleets but is not necessary.

Currently, the Santa Clara Water District has Toyota Prius and Ford Escape Hybrid vehicles which are not recharged using plug-ins to receptacles. If plug-in charging is needed or desired, a 240V line could be installed in conduit in the medians identified in **Figure 2** below for recharging hybrid or dedicated vehicles parked in these adjacent parking slots.

Utilizing the electric vehicle batteries as back-up energy sources for power outages or peak shaving is the subject of research and development by industry participants. For the purposes of this report these types of systems are considered as emerging technologies that are not currently in widespread commercial use as such they were not considered in this evaluation.

4.2 NATURAL GAS REFUELING INFRSTRUCTURE

Due to limited space availability at the existing Santa Clara Water District maintenance yard, it will be difficult to place a compressed natural gas station for compression and storage needed to serve the immediate and long-term needs of the District. Initially one smaller skid mounted compressor and cascade of tanks could be installed with controls, utilities and bays installed initially so that it would be easy to add additional compressors in modular fashion as more vehicles are converted to CNG instead of rebuilding the entire CNG station when additional compression is needed. Regardless, the basic footprint of the CNG station will be 15’ x 50’ to allow room for expansion. The only location that is suitable for a CNG station is shown in Figure 2 depending on setbacks from the river and other potential code issues. The CNG dispensing unit could be located on the existing refueling island now used for diesel and gasoline with piping run from the CNG station. Figure 3 shows a typical layout for a fast fill CNG Station. Typical budget level costs for a CNG Station with dispensing unit to meet the District’s initial needs and prepare for future expansion is estimated to be $300,000-$500,000.

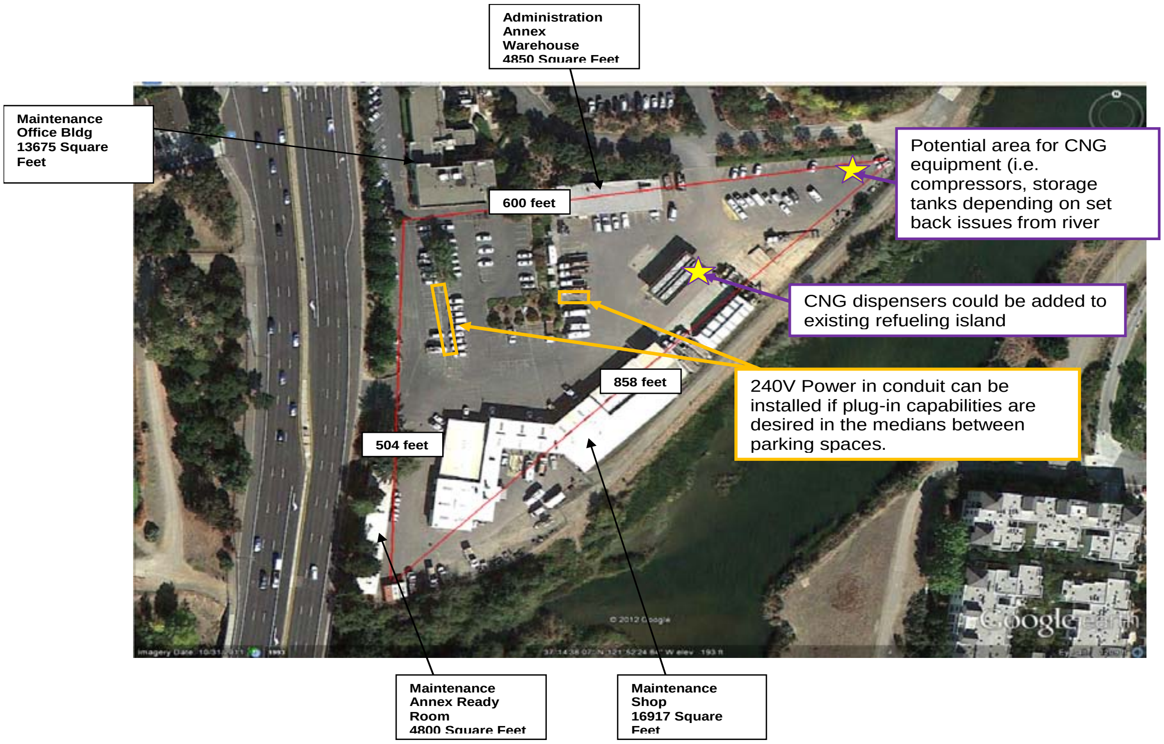

Administration
Annex
Warehouse
4850 Square Feet
Maintenance
Office Bldg
13675 Square
Feet
600 feet
Potential area for CNG equipment (i.e. compressors, storage tanks depending on set back issues from river
CNG dispensers could be added to existing refueling island
240V Power in conduit can be installed if plug-in capabilities are desired in the medians between parking spaces.
858 feet
504 feet
Maintenance
Annex Ready
Room
4800 Square Feet
Maintenance
Shop
16917 Square
Feet

Figure 2 SCVWD Maintenance Yard showing potential plug-in and CNG facilities

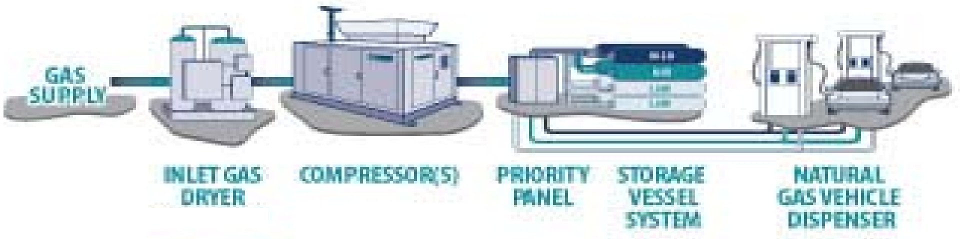


Figure 3 Typical Layout for a Fast Fill CNG Station

Key findings from the assessment of the refueling infrastructure requirements include the following:

- No refueling facilities are needed for hybrid vehicles.
- While a CNG dispensing unit(s) can be added to the existing refueling island, there is limited space for CNG refueling station on existing property.
- Dedicated electric vehicles would be recharged by plug-in receptacles which infrastructure could be installed in existing islands between parking spaces.

5.0 Maintenance Requirements

Maintenance requirements for each of the potential vehicle fleet options will require additional staff and training as well as potentially building modifications for maintenance on certain kinds of vehicles to be performed. According to SCVWD staff, there are currently 5 full time mechanics for hybrid vehicle maintenance, 4 of which are fully trained for hybrid vehicles, 1 is in the process of completing training. The following outlines the maintenance requirements for each of the fleet options:

- Hybrid: additional training for non-hybrid mechanics will be required if a full conversion to hybrid technology is desired. According to SCVWD staff, the current hybrid staff is at full capacity for maintaining the existing hybrid fleet. However, since some the existing staff is already trained, any conversion is expected to go more smoothly.
- Dedicated Electric: While similar to hybrid technology, there are differences and for warranty purposes alone, SCVWD mechanics would have to take additional training to be able to work on dedicated electric vehicles. Black & Veatch believes the sourcing would be through local dealers but that is yet to be confirmed as well as the cost of such training. There does not appear to be any modifications needed to existing facilities to allow mechanics to work on dedicated electric vehicles as long as 240V electric service is available.
- CNG: Maintenance facilities would need to undergo a thorough evaluation and assessment per the pertinent local, state and industry requirements to see if CNG vehicle maintenance can be performed in the buildings without modifications. Black & Veatch understands that there is a welding shop nearby and from the information provided on the maintenance facilities believes that CNG maintenance may be difficult or not be able to be done at all without modifications to the existing facilities. While it is difficult to estimate the cost of such modifications without the above referenced assessment being done, the range of costs could be in the $250-500k range due to the relatively limited space in the maintenance area, presence of welding activity nearby and the separation and ventilation needed for CNG maintenance alone.
- Additionally, SCVWD staff would have to go through training for CNG maintenance which Black & Veatch could be sourced locally through either local utilities or NGV providers. However, there more than likely will be a cost which add more costs to the CNG option.

Key findings from the assessment of the maintenance requirements include the following:

- SCVWD staff are trained on maintenance on hybrid vehicles with one exception and will need training for this staff member as well as additional hybrid maintenance staff if additional hybrids are added to the fleet.
- No building modifications are needed for hybrid maintenance and dedicated electric vehicle maintenance (as long as 240 V service is available)
- Dedicated electric vehicles would be recharged by plug-in receptacles which infrastructure could be installed in existing islands between parking spaces. The District has four (4) 240 volt chargers in the carport system. Modifications most likely would need to be made to existing buildings for CNG maintenance which could be costly. Training for existing staff would be needed for them to work on dedicated electric or CNG vehicles.

6.0 Conclusions and Recommendations

The main conclusions from the Liquids Fuel Analysis are:

- The District consumed approximately 66,300 gallons of gasoline and 2,100 gallons of diesel in last year, or 68,700 gallons of gasoline equivalent. Based on the provided cost of gasoline and diesel, The District spent approximately $212,000 on gasoline and $7,000 on diesel for a total cost of $219,000.
- Based on The District's current replacement policy (12 years, 125,000 miles), and FY2013 replacements, a significant number of vehicles will be up for replacement the next couple of years.
- The existing fleet average fuel economy for the past year was 16.9 miles/GGE.
- There are multiple hybrid vehicle options commercially available to include sedans, light trucks, and SUVs. There are commercially available options for dedicated electric/plug-in hybrids and CNG vehicles, but they are limited to the sedan class.
- No refueling facilities are needed for hybrid vehicles. While a CNG dispensing unit(s) can be added to the existing refueling island, there is limited space for CNG refueling station on existing property. The estimated cost for a CNG Station with dispensing units to meet The District's initial needs and prepare for future expansion is estimated to be $300,000-$500,000. Dedicated electric vehicles would be recharged by plug-in receptacles which infrastructure could be installed in existing islands between parking spaces.
- SCVWD staff are trained on maintenance on hybrid vehicles with one exception and will need training for this staff member as well as additional hybrid maintenance staff if additional hybrids are added to the fleet. No building modifications are needed for hybrid maintenance and dedicated electric vehicle maintenance (as long as 240 V service is available). Dedicated electric vehicles would be recharged by plug-in receptacles which infrastructure could be installed in existing islands between parking spaces. Modifications most likely would need to be made to existing buildings for CNG maintenance which could be costly. Training for existing staff would be needed for them to work on dedicated electric or CNG vehicles.

Based on the results of this assessment, Black & Veatch recommends that SCVWD continue purchasing hybrid vehicles where possible as part of their replacement program for the following reasons:

- There are commercial available hybrid vehicles for cars, SUVs, and light trucks. The number of available hybrid vehicles has grown in the past years and is expected to increase in the future. Further, the fuel economy of hybrids is getting better. Finally, there are limited commercial options (sedans or 3rd party conversions) for CNG and dedicated electric vehicles.
- Conversion to available hybrid vehicles will increase fuel efficiency for cars, SUVs, and light trucks (Rangers, F-150s) from an estimated 19.9 miles/GGE (Existing Fleet) to 30.6 miles/GGE, a 54 percent increase in fuel economy (NOTE: average fuel economy based on miles driven in the past year by vehicle type). Figure 4 shows the potential fuel economy gain for a hybrid conversion based on commercially available vehicles. Fuel economy gains are also shown in Table 4.
- No refueling facilities are needed for hybrid vehicles. While a CNG dispensing unit(s) can be added to the existing refueling island, there is limited space for CNG refueling station on the existing property. Dedicated electric vehicles would require infrastructure upgrades for plug-in receptacles between parking spaces.

- SCVWD staff are trained on maintenance on hybrid vehicles. Additional trained maintenance staff will be required for a hybrid fleet conversion. However, since almost all of the existing staff is already trained, continuing the existing program to purchase hybrid vehicles when possible is more beneficial and economic than either the Dedicated electric or CNG options. Further, no building modifications are needed for hybrid maintenance.
- Training for existing staff would be needed for maintenance on dedicated electric or CNG vehicles.
- No building modifications are needed for dedicated electric vehicle maintenance (as long as 240 V service is available). Modifications most likely would need to be made to existing buildings for CNG maintenance which could be costly.

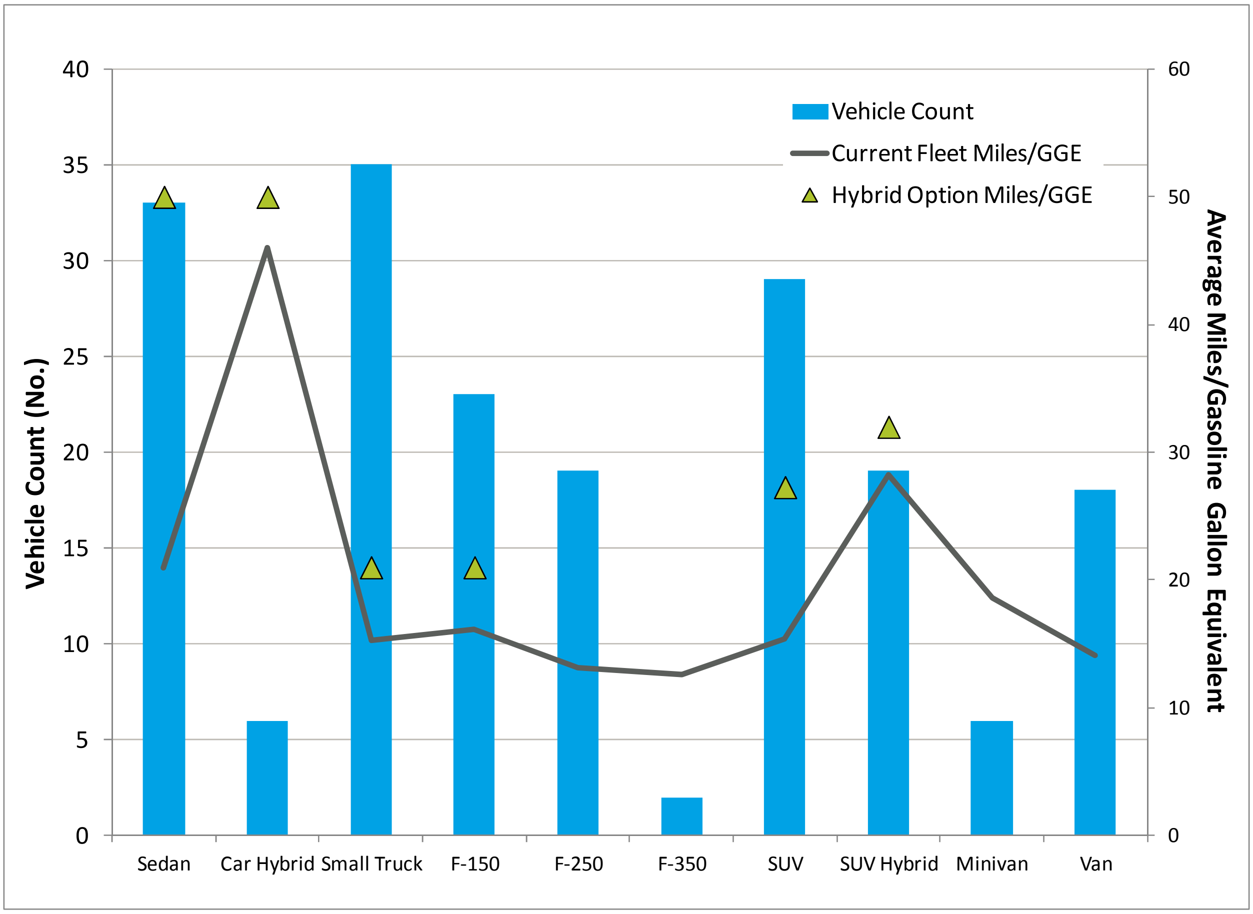


Figure 4 Current Fleet Vehicles and Fuel Economy and Hybrid Option Fuel Economy

FINAL

ENERGY OPTIMIZATION PLAN

Anderson Hydroelectric Facility Optimization Evaluation

B&V Project No. 178292

Prepared for

Santa Clara Valley Water District

FEBRUARY 2013

BLACK & VEATCH

Table of Contents

Executive Summary **1**
Anderson Hydroelectric Optimization 1
1 Introduction **3**
2 The Anderson Hydroelectric Facility **4**
2.1 System Description 4
2.2 Assessment of Existing Equipment Conditions 5
3 Recommendations **6**
3.1 Investments in the Hydroelectric Facility for Optimizing Energy Generation 6
3.2 Operation and Maintenance of the Hydroelectric Facility for Improving Energy Generation 7
3.3 Maintenance of the Facility for System Reliability 8
4 Conclusions **10**

LIST OF FIGURES

Figure 1 Photo of the two Francis type turbines at Anderson Hydroelectric Facility. 5
Figure 2 Turbine bearing cooling system modification. 5
Figure 3 Wicket Gate Hydraulic Controls 6
Figure 4 2011 Flow Duration Curve 10

Executive Summary

ANDERSON HYDROELECTRIC OPTIMIZATION

As part of SCVWD's Energy Optimization Plan, the Anderson Hydroelectric Facility was evaluated for opportunities to optimize energy generation or lower long term costs. The assessment of Anderson Hydroelectric Facility primarily consisted of assessing the operating methods, the power generation equipment, maintenance practices, and the availability of head and flows.

The Anderson Hydroelectric Facility was constructed in 1987 and includes two Francis turbines each with a rated head of 165 feet. Obligation to meet the downstream flow and recharge requirements of Coyote Creek dictate the amount of flow available for power generation at Anderson Hydroelectric Facility. This flow can be as high as 50 cfs but is generally much less, with an average flow of 24.9 cfs during 2011. The Anderson Hydroelectric Facility also has a 30 inch bypass line that is regulated by a 20 inch Polyjet energy dissipating valve.

The key findings and recommendations from the assessment of the facility include the following:

Investments in the Hydroelectric Facility for Optimizing Energy Generation

Due to the restrictive flow regime the facility currently has to be operated under, no immediate capital investments in the facility were identified that could significantly improve or optimize energy generation of the facility.

Operation and Maintenance of the Hydroelectric Facility for Improving Energy Generation

The following are recommended for improving energy generation:

- Have the offsite SCADA system operator incorporate a set practice of at least twice per day checks of current flow conditions, adjusting the wicket gate position for best efficiency if/when possible, and ensuring that the units are not operated outside their manufacturer recommended operating ranges.
- Validate that the flowmeter reading is as accurate as possible.
- Continue to ensure that the 36 inch diameter butterfly "guard" valve is completely open whenever the turbine is in operation, and update the facility O&M manuals accordingly if needed.
- Validate that the 20 inch energy dissipating valve is closing completely.
- Perform turbine index tests as a relatively inexpensive way to establish the shape of the efficiency curve for the turbines.
- Consider evaluating whether or not the current contractual requirements that limit the use of USBR water for meeting the flow requirements of Coyote Creek through the turbines should be revisited.

Maintenance of the Facility for System Reliability

The following are recommended for improving facility reliability and availability:

- Perform regular tests to insure the proper operation of the existing over-speed event trip scheme verifying the 24 inch butterfly turbine shutoff valve (TSV) closing on loss of grid or over-speed.
- Consider adding a small drain valve to each of the turbine units.

1 Introduction

SCVWD's economic and environmental goals have led the District to develop an Energy Optimization Plan. As part of this effort, the present means and methods of operating and maintaining the Anderson Hydroelectric Facility were evaluated for opportunities to improve energy generation.

This report presents the results of a hydroelectric system evaluation for the Anderson Hydroelectric Facility. The evaluation included the following primary components:

- Review of available Anderson Hydroelectric Facility information including:
    - Selected site drawings.
    - Operation and Maintenance Manuals for Anderson Hydroelectric Facility.
    - Anderson Hydroelectric Facility Operations Evaluation Report from April 1999.
    - District Hydroelectric Power Potential report by Salas O'Brien Engineering Inc from March 2002.
    - Available flow and head data of the Anderson Hydroelectric Facility for 2011 and partially available for 2010 and 2012.
    - Engineering Vibration and Temperature analysis report written by District mechanical engineering in November 2011. This included details about repairs made to the turbines during the overhaul done prior to the testing that was carried out.
    - Data from a July 2011 over-speed event.
    - Several preventive maintenance records from the Maximo CMMS including PM Job Plans.
- Site visit to facility on October 9, 2012, during which the powerhouse, metering, and bypass facilities were inspected, with the following participants (for all or part of the site visit):

    SCVWD: Alan Zeisbrich, Arvind Tailor, Mae Siendo, Larry Wong, Chris Howard, John Alise, Steve Harris

    Black & Veatch: Tom Brittain, Jake Snyder
- Assessment of existing conditions, including equipment condition, available head and flow conditions, timing, duration and magnitude of flows through the hydroelectric facility and any water bypass or discharge that does not pass through the hydroelectric facility.
- Recommendations on opportunities to repair or rehabilitate the facilities and changes in operation and maintenance procedures to optimize energy generation or lower long term costs.

Note that this evaluation was based solely on the site visit and the information and data provided by SCVWD; no measurements or performance testing were conducted.

2 The Anderson Hydroelectric Facility

2.1 SYSTEM DESCRIPTION

The Anderson Hydroelectric Facility was constructed in 1987 and is comprised of a two-unit powerhouse with each unit having a maximum flow capacity of 37 cfs at 190 feet of head. The Anderson Hydroelectric Facility is required to discharge up to 50 cfs to Coyote Creek in order to meet downstream flow needs and recharge requirements. A 36 inch diameter pipe branches from the 54 inch diameter Anderson Force Main to supply both turbines. A 20 inch Polyjet energy dissipating valve provides the capacity to completely bypass the turbines to meet the discharge requirements.

The two Francis type turbines, manufactured by Worthington Pump Division of Dresser Industries, each have a rated head of 165 feet at an operating speed of 1210 RPM. Two induction generators, manufactured by Siemens, are each designed to produce 470 kW at 1210 RPM.

The general estimate of flow and the factors that are used to set the flow were provided by SCVWD. The information provided indicates that the flow varies between 15 and 50 cfs and is contingent on the amount of water needed to maintain the required flow in Coyote Creek. The amount of flow release needed depends on several factors, including the season of the year, the amount of ground moisture, local groundwater elevation, the lack of uncontrolled runoff, the increased needs of the riparian corridor and the amount of evaporation. The flow to Coyote Creek can be changed from day to day but will generally not be varied throughout the day.

The annual generation of Anderson Hydroelectric Facility is limited by the flow SCVWD is required to discharge into Coyote Creek. Due to this constraint the potential capacity of the two turbine-generators, which is approximately 800 kW, is never realized.

Available head and flow data, recorded in the SCVWD SCADA system, was provided for the period from April 15, 2010 through September 27, 2012. The maximum static head to the turbine is 220 feet and the minimum head is 100 feet. For the 2011 season, the recorded average head was 167 feet and the average flow, when the turbine was producing power, was 24.8 cfs. During 2011 the energy output totaled 2,213 MWh. As long as all the available flow is processed by the turbines, the maximum amount of power will be generated.

The G11 and G12 units are remotely operated via observed total flow data on the SCADA system through the 36 inch Anderson Hydroelectric Facility water supply line. While the operator can use a spreadsheet, created from the turbine's efficiency curve (Hill Chart) to determine the best wicket gate position for efficiency, system flow is not able to be adjusted for efficiency. The operator inputs the wicket gate position as a set-point value for the wicket gate control system which meets the requirements of the flow regime set by regulatory agencies. If not closely monitored, this can put the turbines in operating zones that are both inefficient and hard on the turbine runners, potentially leading to cavitation damage.

2.2 ASSESSMENT OF EXISTING EQUIPMENT CONDITIONS

2.2.1 Turbines

The Anderson Hydroelectric Facility is equipped with two Francis type turbines manufactured by the Worthington Company. Shown in Figure 1 to the right, each turbine unit is supplied by its own 24 inch diameter supply pipe from a single 36 inch pipe. The design head of the turbines is 150 feet with peak efficiency at a flow of 29 cfs. The turbine's efficiency curve, provided by the manufacturer, shows that the turbines have an operating head range between 100 feet and 220 feet. This curve also shows an operating flow range between 15 cfs and 37 cfs depending on the head. Units G11 and G12 have cast stainless steel runners. There is a spare runner at the facility with low operating time on it. SCVWD operations personnel indicate that Unit G12 has maintained its original shaft but Unit G11 shaft has been replaced as much as three times throughout several overhauls. The last G11 shaft was replaced in 2005 during the overhaul of both units. Based on a report done by District mechanical engineering, the turbine bearing temperature of Unit G12 consistently runs approximately 25 degrees Fahrenheit higher than Unit G11.

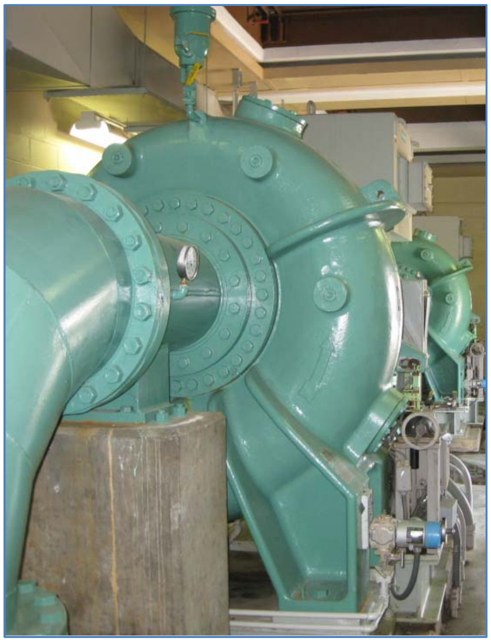


Figure 1 Photo of the two Francis type turbines at Anderson Hydroelectric Facility.

2.2.2 Turbine Shutoff Valves

The turbine shutoff valves are 24 inch motor operated butterfly valves. The use of an AC electric motor operator for turbine shutoff valves presents risk of uncontrolled overspeed if the wicket gates fail to close following a load rejection event caused by loss of grid power. Generally, turbine shutoff valves rely on stored energy to close. This stored energy may be inlet water pressure, hydraulic oil, a spring, or a counter-weight. Runaway situations have been experienced by the units, causing damage to the bearings and multiple turbine shafts.

There is also a manually operated 36 inch butterfly "guard" valve ahead of the turbine supply lines. SCVWD staff reported that the valve has been used to throttle head to the turbines in the past, which it is not designed to do and should not be required to do since the maximum available head is equal to the highest head the turbine should operate at.

2.2.3 Cooling Water System

Cooling water for the generator and bearing is taken from the penstock. Shown in Figure 2, the exterior mounted cooling plate modification was added to the turbine bearing housing of each unit. A bearing oil temperature sensor was also added during this modification.

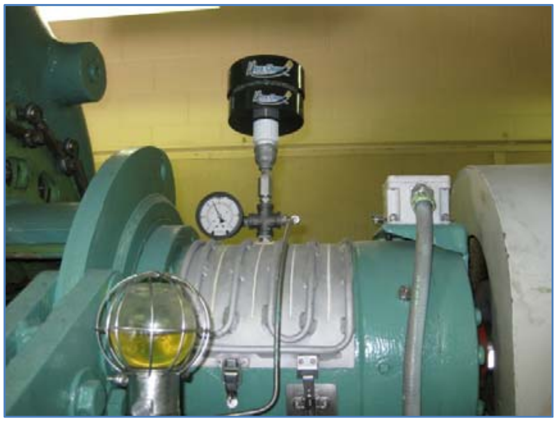


Figure 2 Turbine bearing cooling system modification.

2.2.4 Wicket Gate Hydraulic Controls

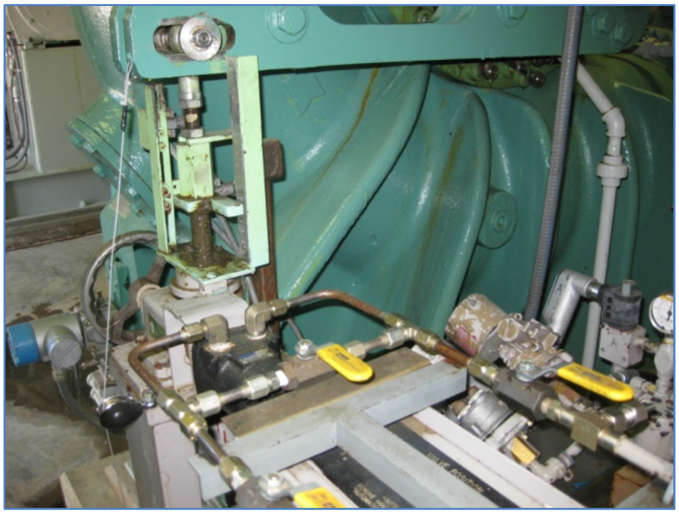


Figure 3 Wicket Gate Hydraulic Controls.

Units G11 and G12 flows are regulated by hydraulic motor operated wicket gate positioning systems. The system, one of which is shown in Figure 3, can be controlled manually or automatically. The piston style accumulator tanks associated with the hydraulic system were replaced in 2010, and during the 2005 overhaul the wicket gates were found to be out-of-time and were adjusted back to manufacturer's specification. This system is normally controlled by a remote operator who establishes a wicket gate percentage open set-point based on flow and head conditions. The original manuals indicate that while the automatic control of the wicket gate actuation is possible, it is not recommended over regularly monitored manual operation. The wicket gate hydraulic controls do not have any sort of oil filtering system or desiccant air breather. There is also no convenient place for maintenance personnel to sample the oil. These aspects of the hydraulic controls can weigh heavily on the wear of the systems components and can cause failures and the need for excess maintenance.

2.2.5 Surge/Pressure Regulator Valve

Each turbine supply pipe is equipped with an eight inch water operated pressure regulator valve. The 50 RWR model valve, manufactured by Ross Valves, is a pilot operated valve capable of rapid opening when the line pressure exceeds its setting. A factory installed strainer is part of the valve setup that requires a regular maintenance practice of flushing or cleaning. Also, there is a vent hole in the base of the valve designed for observing the condition of the packing which aids in diagnosing the valve's overall condition. This hole, known a vent hole "C" in the valve's manual, is unable to be observed due to the way the support for the valve was installed.

2.2.6 Bypass Valve

A 20 inch diameter Bailey Polyjet energy dissipating valve controls the bypass flow at the Anderson Hydroelectric Facility. During the site visit it was observed that the valve indicated that it was fully closed. However upon inspection water was heard still passing through it.

3 Recommendations

3.1 INVESTMENTS IN THE HYDROELECTRIC FACILITY FOR OPTIMIZING ENERGY GENERATION

Due to the restrictive flow regime the facility currently has to be operated under, contingent on the amount of water needed for maintaining the required flow to Coyote Creek, no immediate improvements or investments in the facility that could be made for the optimization of energy generation were noted.

If the flow regime was to increase to a point where both units could operate simultaneously for a majority of the time, the Anderson Hydroelectric Facility should be re-evaluated for potential gain in energy generation.

3.2 OPERATION AND MAINTENANCE OF THE HYDROELECTRIC FACILITY FOR IMPROVING ENERGY GENERATION

Attention to certain operational details will make positive impacts in the operating performance of Anderson Hydroelectric Facility. These include:

- Having the offsite SCADA system operator incorporate a set practice of at least twice per day checks of current flow conditions, adjusting the wicket gate position for best efficiency if/when possible, and ensuring that the units are not operated outside their manufacturer recommended operating ranges.

  Current District practice employs the use of a "Wicket Gate Opening Percentage" spreadsheet to regulate the flow to Coyote Creek and attempt to generate power as efficiently as possible. This spreadsheet is based on the manufacturer recommended operating parameters per unit known as the "Hill Chart". Operating outside these ranges increases the potential for damage from cavitation and can reduce the units potential output capabilities.

  Incorporating twice a day checks will help to establish a routine of checking and adjusting all of the operating parameters for Anderson Hydroelectric Facility, including for operating as efficiently as possible given the flow requirements set by Coyote Creek demand.

- Making sure that the flowmeter reading is as accurate as possible.

  During the site visit, it was noted that the ultrasonic flowmeter on the 36 inch Anderson Hydroelectric Facility supply pipe (Badger model 4100) is installed in a location that is right on the edge of installation guidelines (for a minimum distance of three pipe diameters between the flowmeter and any downstream obstruction; in this case a 90 degree turn in the pipe), which per SCVWD maintenance personnel has resulted in inaccuracies in the flow readings having been observed over time.

  The successful and accurate operation of this flowmeter is the only way to confirm the actual flow to the facility. This presents the unfortunate situation of not being able to know how much flow is actually going to units, information required by the operators to allow them to ensure that the units are being run as efficiently as possible. If upon re-calibration of the flowmeter it is determined that it is incapable of being accurate, additional steps are recommended to move or adjust the meters location to achieve more accurate readings, or to provide alternate means of measuring the flow.

- Continuing to ensure that the 36 inch diameter butterfly "guard" valve is completely open whenever the turbine is in operation, and update the facility O&M manuals accordingly if needed.

  Impeding the flow through the 36 inch supply pipe uses energy which is then unavailable to the turbines, and also results in vibrations which increase the more the valve is closed.

  Additionally, this valve should not be used for throttling service, if the conditions were to arise where throttling head was actually needed, as the best way to reduce the head would be to limit the flow by adjusting the wicket gate opening.

- Making sure that the 20 inch energy dissipating valve is closing completely.

  It is important that the energy dissipating valve close completely to direct all available flow to the turbines, especially due to the available flow to the Anderson Hydroelectric Facility being generally less than optimum, so that usable flow is not being lost via the bypass.

  If/as needed, possible repairs could include adjusting the limit switch to ensure that it doesn't sense full closed unless the valve is actually fully seated and completely shut or replacing the packing and/or the leading seal ring (if the valve continues to leak at its closed position).

  Again, it is important to note that any flow that has potential to be used by the turbines but is bypassed through this valve is a loss of recoverable energy.

- Performing turbine index tests as a relatively inexpensive way to establish the shape of the efficiency curve for the turbines.

  Turbine efficiency is the ratio of mechanical power output divided by hydraulic power input. Hydraulic power input is the product of head (pressure) and flow. Absolute efficiency tests provide actual numerical efficiency data but are relatively expensive to conduct.

  An index test is conducted by measuring generator power output. An index test curve identifies the wicket gate opening for peak efficiency and the drop in efficiency at other wicket gate openings.

  Index tests should be performed as a long term component of a turbine condition monitoring program, on a 5 year cycle or when problems are noted, and can show the change in efficiency over time.

- Considering evaluating whether or not the current contractual requirements that limit the use of USBR water for meeting the flow requirements of Coyote Creek through the turbines should be revisited.

  If there are enough scenarios where Anderson Reservoir water cannot meet the potential demands through the hydro and energy generating potential is being lost, then it could be in the interest of the District to explore new options for making this water available for generation.

  Recently the Bureau of Reclamation released an updated Directive, FAC 04-08, that SCVWD might find applicable to obtaining the rights to use the imported water in their turbines.

3.3 MAINTENANCE OF THE FACILITY FOR SYSTEM RELIABILITY

At Anderson Hydroelectric Facility, lowering maintenance and repair costs are the most direct way to improve the economics of the power generation system. Therefore, it should be made sure that the following items are included in the facility maintenance planning:

- Performing regular tests to insure the proper operation of the existing over-speed event trip scheme verifying the 24 inch butterfly turbine shutoff valve (TSV) closing on loss of grid or over-speed.

  Over-speed events can damage the turbine's shaft and bearings. Using the TSVs, and not relying only on the closing of the wicket gates, to more quickly shut off flow on over-speed trips, is the recommended way to safeguard the equipment. So, the existing trip scheme should be reviewed and tested to ensure that it is functional in all conditions, including loss of grid/power to the TSV actuators. Tests can be performed simulating each of the methods of tripping that can occur to determine that the major pieces of equipment respond properly.

Load rejections can occur from different causes, but generally start with the loss of the grid that the generator is connected to or the opening of the generator circuit breaker for one of multiple reasons. A complete review of the modified electrical circuits to make sure there's no way that the generator circuit breaker opening or loss of grid can occur that does not result in the shutting of the TSVs and the closing of the wicket gates is recommended.

A test program where load rejections are simulated every three to five years will assure that the protection system is functioning properly. Annual tests of major trip functions will show that the wicket gates and TSV will close on demand. The turbine-generators should not be operated if any one of these safety systems does not work.

- Strongly considering adding a small drain valve to each of the turbine units.

  When flows do not warrant dual operation, there is potential for corrosion to the equipment. As shown in Figure 4 below, the Flow Duration Curve shows that the flow at Anderson Hydroelectric Facility warranted the use of only one turbine 81% of the year. This flow pattern results in only one turbine being operated while the other is left idle for that portion of time. During this time stagnant water in the idle unit can lead to corrosion on the runner. SCVWD operations indicated that it is current practice to rotate the units at each generating stop and start point. Due to the inability to know how long these generating periods might be, as predicting what flow Anderson Hydroelectric Facility will have is contingent on Coyote Creek demand, it is difficult to set a rigid schedule that the units must be rotated on using this approach. If units continue to have long shutdown periods, draining the unit would be the best way to prevent corrosion to the equipment.

  If this is not feasible, investigate and execute a rotational program of the turbines, when flows do not warrant dual operation, which will occur often enough to prevent damage to the runners.

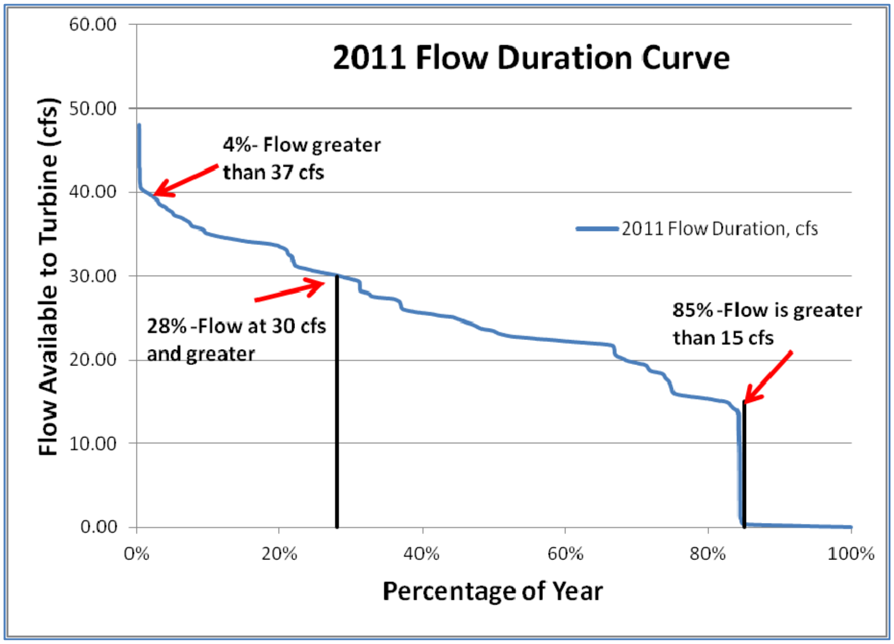


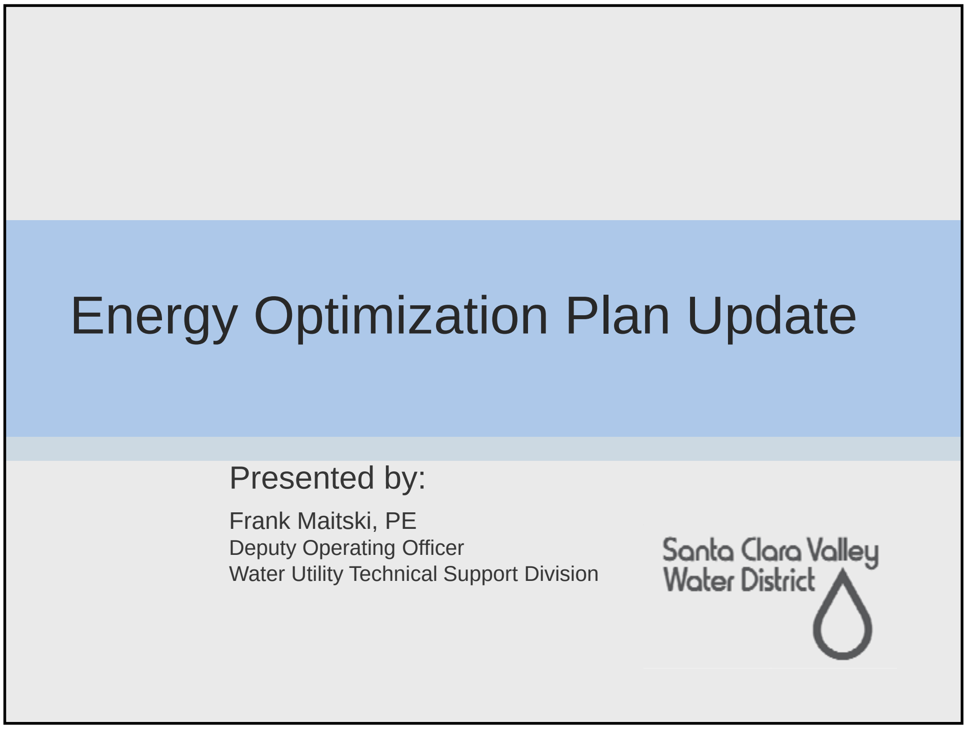
Figure 4 2011 Flow Duration Curve.

4 Conclusions

The Anderson Hydroelectric Facility has restrictive flow regime requirements as such there are limited operational changes that could be made to improve energy generation. In order to conform to these required flows, reduce the potential for cavitation and help to identify mechanical problems before they can cause severe damage, an Anderson Hydroelectric Facility condition monitoring and wicket gate position adjustment practice by the remote operator should occur twice daily. During this monitoring procedure attention must be given to the position of the bypass valve, assuring that all available water is directed through the turbines. A brief review of operating parameters should reveal normal operation, or lead to action before excessive damage occurs.

At Anderson Hydroelectric Facility lowering maintenance and repair costs are the most direct way to improve the economics of the power generation system. Implementing routine tests of the over-speed trip scheme that includes closing the wicket gates and the TSV, will ensure that the shutdown procedure and equipment is working reliably and greatly reduce the opportunity for costly damage to occur to the G11 and G12 units.

Incorporating selective monitoring, inspection and adjustment practices at Anderson Hydroelectric Facility will allow power generation to take place with the least amount of unnecessary cost and down time.

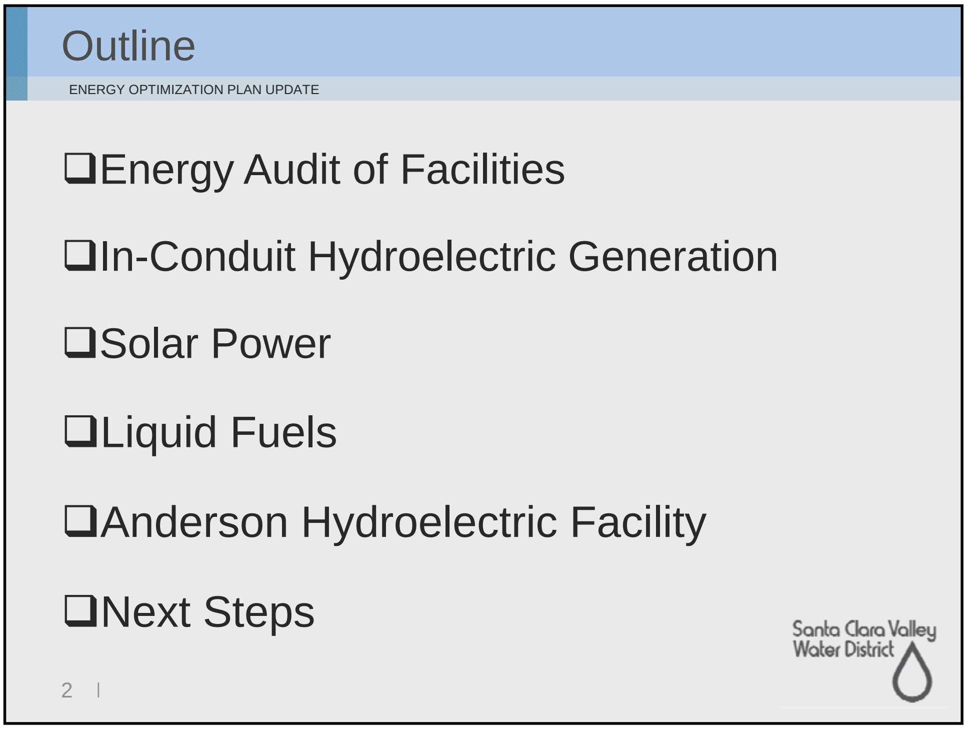


Energy Optimization Plan Update

Presented by:

Frank Maitski, PE
Deputy Operating Officer
Water Utility Technical Support Division

Santa Clara Valley Water District

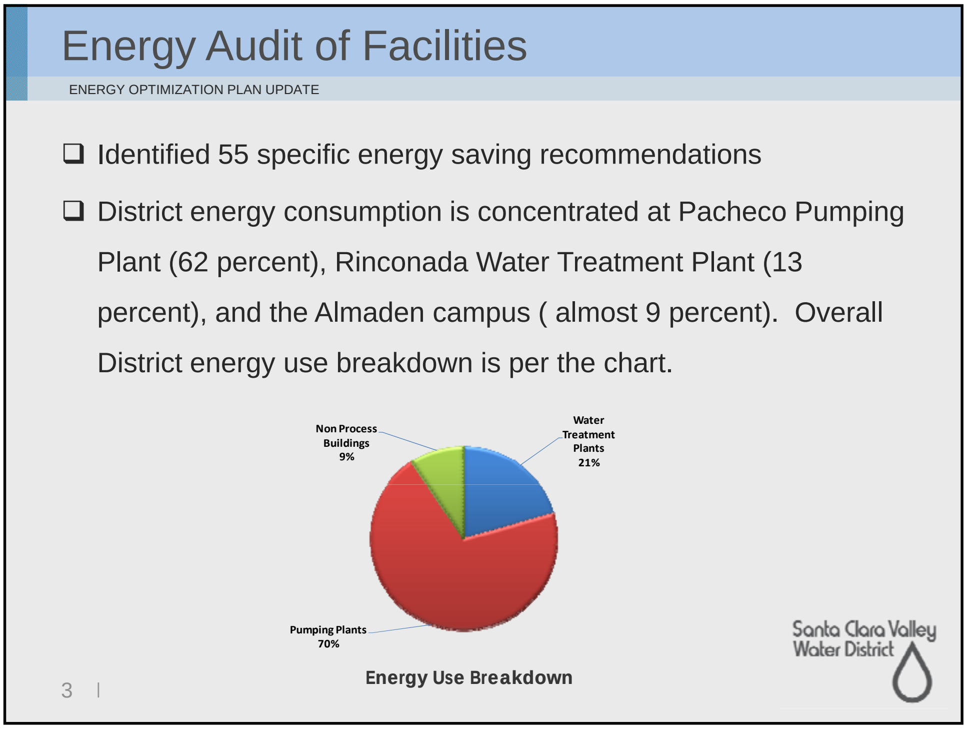


Outline

ENERGY OPTIMIZATION PLAN UPDATE

- ❑Energy Audit of Facilities
- ❑In-Conduit Hydroelectric Generation
- ❑Solar Power
- ❑Liquid Fuels
- ❑Anderson Hydroelectric Facility
- ❑Next Steps

Santa Clara Valley Water District

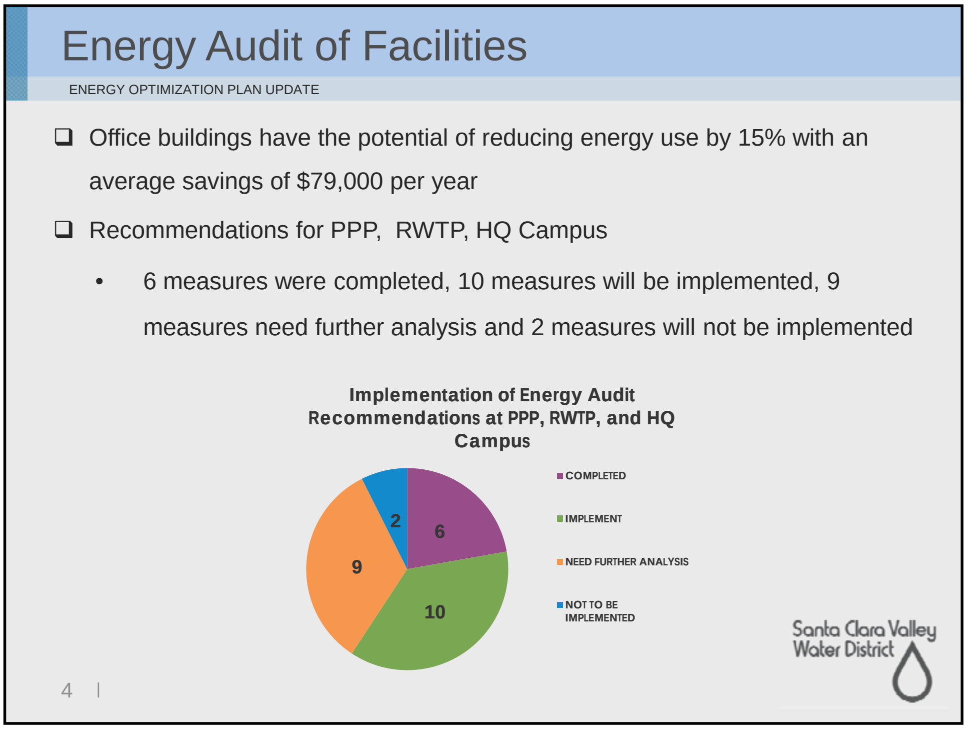


Energy Audit of Facilities

ENERGY OPTIMIZATION PLAN UPDATE

- ❑ Identified 55 specific energy saving recommendations
- ❑ District energy consumption is concentrated at Pacheco Pumping Plant (62 percent), Rinconada Water Treatment Plant (13 percent), and the Almaden campus (almost 9 percent). Overall District energy use breakdown is per the chart.

Energy Use Breakdown



Energy Audit of Facilities

ENERGY OPTIMIZATION PLAN UPDATE

- ❑ Office buildings have the potential of reducing energy use by 15% with an average savings of $79,000 per year
- ❑ Recommendations for PPP, RWTP, HQ Campus
  - 6 measures were completed, 10 measures will be implemented, 9 measures need further analysis and 2 measures will not be implemented

Implementation of Energy Audit Recommendations at PPP, RWTP, and HQ Campus

In-Conduit Hydroelectric Generation

ENERGY OPTIMIZATION PLAN UPDATE

- Team evaluated 41 sites throughout the District's water transmission and distribution system
- 13 sites identified with the potential for hydroelectric generation. Nine out of the 13 sites are economically viable
- Potential savings of $26.2 M over the next 50 years for 9 sites. Cost of energy ranges from $49 to $122 per MWh
- The nine sites could produce 11,000 MWh of electrical power annually, eight percent of the District's total Calendar Year (CY) 2011 electrical usage
- Staff plans to present the report to the retailers and proceed with the CIP project validation

Santa Clara Valley Water District

In-Conduit Hydroelectric Generation

ENERGY OPTIMIZATION PLAN UPDATE

Hostetter Turnout

Typical In-Conduit Installation

Santa Clara Valley Water District

Solar Power

ENERGY OPTIMIZATION PLAN UPDATE

- ❑ Team evaluated three vacant District-owned sites for potential PV installation and

Site 1
East Foothills
10.8 Acres
Proposed East Reservoir Project not constructed

Site 2
Coyote Creek
17.7 Acres
Portion of property used for canal

Site 3
Morgan Hill
15.3 Acres
Recharge Ponds

Solar Power

ENERGY OPTIMIZATION PLAN UPDATE

- ❑ Potential PV Sites at Santa Teresa and Penitencia Water Treatment Plants

Site 4
PWTP
.7 Acres

Site 5
STWTP
2.6 Acres

Solar Power

- The five sites can produce 21,000 MWh of energy per year, or about 15 percent of the District's 2011 usage
- Three Development Approaches
  - Build and Own - $121 to $144 per MWh
  - PPA (Power Purchase Agreement) - $105 to 129 per MWh
  - Pre-Pay PPA - $87 to $106 per MWh
- Staff recommendation – PWRPA solar power farms ranges from $75 to $100 per MWh due to economy of scale

Santa Clara Valley Water District

Liquid Fuels

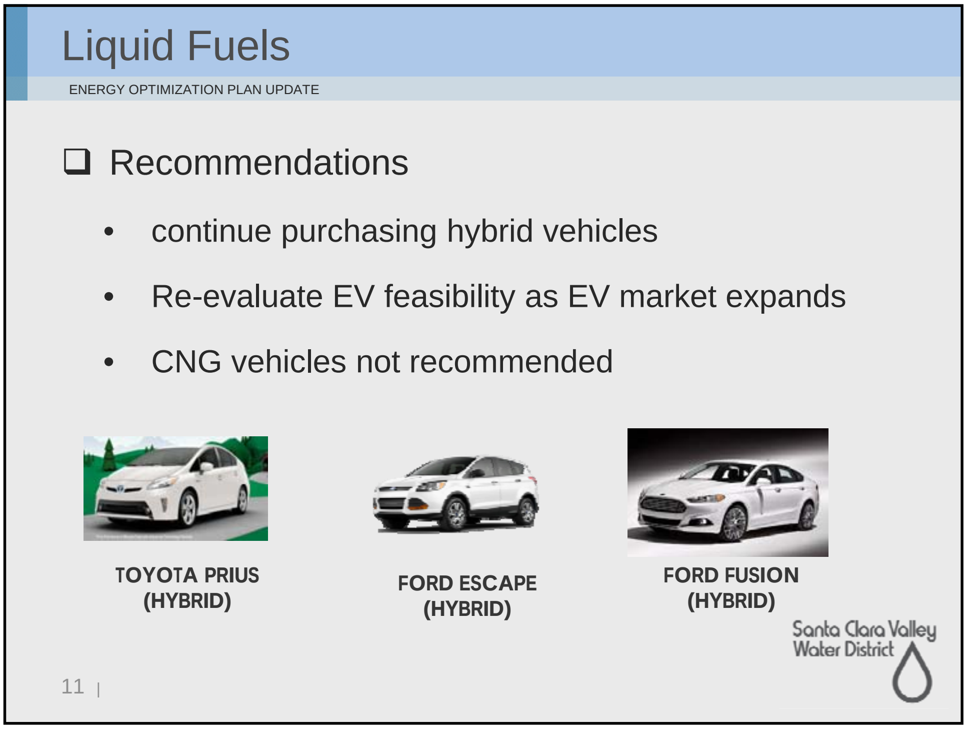
- Alternatives to gasoline and diesel fuel for sedans, SUVs, and light duty trucks
  - commercially available options for hybrid, electric, and compressed natural gas (CNG) vehicles

NISSAN LEAF (ELECTRIC)

TOYOTA PRIUS (HYBRID)

Honda Civic (CNG)

Santa Clara Valley Water District



Liquid Fuels

ENERGY OPTIMIZATION PLAN UPDATE

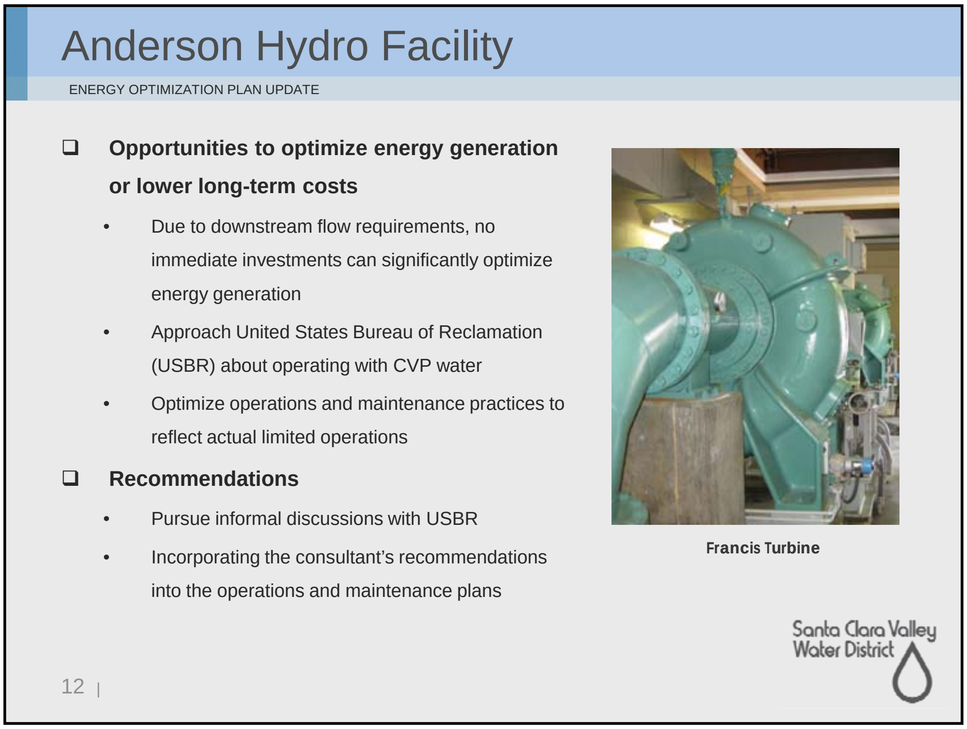
☐ Recommendations

- continue purchasing hybrid vehicles
- Re-evaluate EV feasibility as EV market expands
- CNG vehicles not recommended

TOYOTA PRIUS (HYBRID)

FORD ESCAPE (HYBRID)

FORD FUSION (HYBRID)



Anderson Hydro Facility

ENERGY OPTIMIZATION PLAN UPDATE

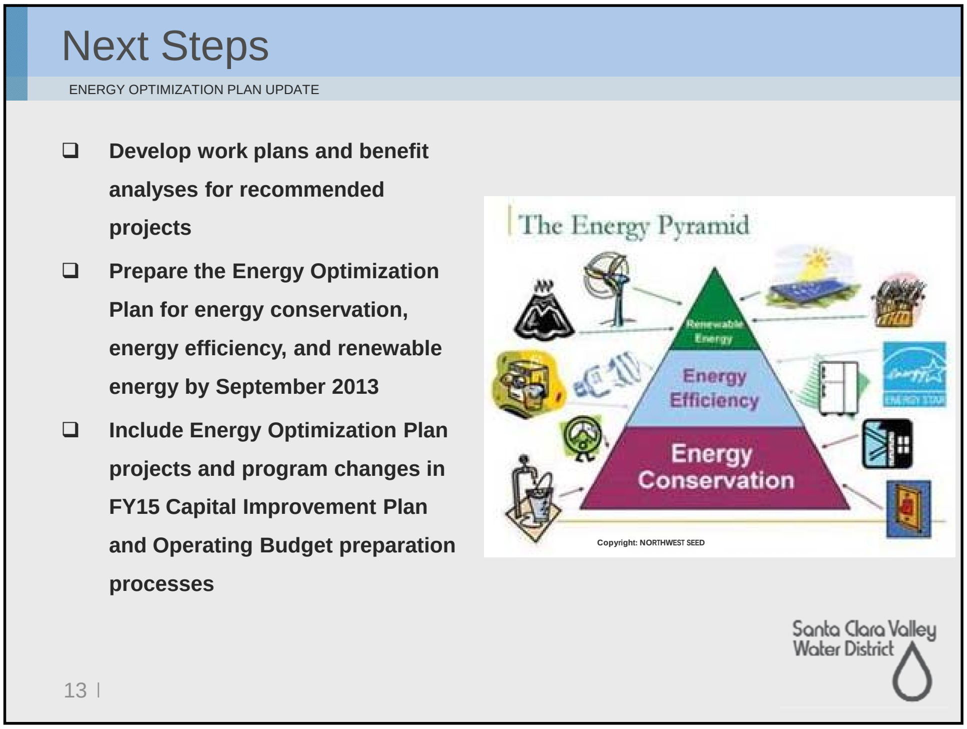
☐ **Opportunities to optimize energy generation or lower long-term costs**

- Due to downstream flow requirements, no immediate investments can significantly optimize energy generation
- Approach United States Bureau of Reclamation (USBR) about operating with CVP water
- Optimize operations and maintenance practices to reflect actual limited operations

☐ **Recommendations**

- Pursue informal discussions with USBR
- Incorporating the consultant’s recommendations into the operations and maintenance plans

Francis Turbine



Next Steps

ENERGY OPTIMIZATION PLAN UPDATE

- ❑ Develop work plans and benefit analyses for recommended projects
- ❑ Prepare the Energy Optimization Plan for energy conservation, energy efficiency, and renewable energy by September 2013
- ❑ Include Energy Optimization Plan projects and program changes in FY15 Capital Improvement Plan and Operating Budget preparation processes

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